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ADJUDICATIONS STAFF

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	March 30, 2007
AmerGen Energy Company, LLC	)	
	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AMERGEN ENERGY COMPANY, LLC MOTION FOR SUMMARY DISPOSITION ON CITIZENS' DRYWELL CONTENTION

1-WA/2677106

TEMPLATE = SECY-041

SECY-02

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I. INTRODUCTION

AmerGen Energy Company, LLC ("AmerGen") hereby requests that the Atomic Safety and Licensing Board ("Board") grant summary disposition, pursuant to 10 C.F.R. § 2.1205, in favor of AmerGen on Citizens'[1] sole contention admitted by the Board related to the frequency of AmerGen's ultrasonic testing ("UT") of the drywell shell in the "sand bed" region of the Oyster Creek Nuclear Generating Station ("OCNGS").

The record in this proceeding and the sworn affidavits accompanying this Motion demonstrate that there is no genuine issue as to any material fact, and that AmerGen is entitled to a decision in its favor as a matter of law. In particular, there is no genuine issue of material fact that calls into question whether AmerGen's scheduled UT monitoring frequency for the sand bed region of the drywell is sufficient to maintain an adequate safety margin, in accordance with U.S. Nuclear Regulatory Commission ("NRC") requirements applicable to the renewal of the OCNGS license. Because AmerGen's UT monitoring frequency fully complies with those applicable requirements, AmerGen is entitled to a decision as a matter of law.

Section II of this Motion sets forth the applicable NRC legal standards governing summary disposition motions and license renewal. Section III frames Citizens' admitted contention by addressing those issues that are within the scope of the contention and those that are not. Section IV presents technical background necessary to understand why the admitted contention is based on speculation, a misunderstanding of the governing acceptance criteria, and simple math errors. Section V discusses why there are no genuine issues of material fact and why AmerGen is entitled to a decision as a matter of law. The latter section is supported by

[1] "Citizens" are comprised of: Nuclear Information and Resource Service; Jersey Shore Nuclear Watch, Inc.; Grandmothers, Mothers and More for Energy Safety; New Jersey Public Interest Research Group; New Jersey Sierra Club; and New Jersey Environmental Federation.

various sworn affidavits, which are appended to this Motion, Section V provides AmerGen's conclusions.

II. LEGAL STANDARDS

Pursuant to 10 C.F.R. § 2.1205(c), the Board must base its ruling on a summary disposition motion in this Subpart L proceeding on the standards for summary disposition set forth in 10 C.F.R. § 2.710, as applied to the license renewal regulations set forth in 10 C.F.R. Part 54.

A. Standards for Summary Disposition

This proceeding is governed by the informal adjudicatory procedures prescribed in Subpart L of 10 C.F.R. Part 2.[2] Pursuant to 10 C.F.R. § 2.1205 in Subpart L, any party may submit a motion for summary disposition at least 45 days before the commencement of a hearing.[3] The motion must be in writing and include a written explanation of the basis for the motion, and affidavits to support statements of fact.[4]

In ruling on the motion, the Board is directed to apply the standards for summary disposition in Subpart G of Part 2, which are set forth in Section 2.710(d)(2).[5] Pursuant to that section, "the presiding officer shall render the decision sought if the filings in the proceeding ..., together with the statements of the parties and the affidavits, if any, show that there is no genuine issue as to any material fact and that the moving party is entitled to a decision as a matter of law."[6] Section 2.710 generally retains the provisions in former Section 2.749, prior to the

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[2] *AmerGen Energy Co., LLC* (License Renewal for Oyster Creek Nuclear Generating Station), LBP-06-07, 63 N.R.C. 188, 228 (2006) ("LBP-06-07").

[3] 10 C.F.R. § 2.1205(a).

[4] *Id.* A separate statement of facts is not required under Subpart L. *Compare id. with* 2.710(a); *see also* 69 Fed. Reg. 2182, 2228 (Jan. 14, 2004) (section 2.1205 "provides a simplified procedure for summary disposition in informal proceedings.").

[5] 10 C.F.R. at § 2.1205(c).

[6] *See Exelon Generation Company, LLC* (Early Site Permit for Clinton ESP Site), LBP-05-19, 62 N.R.C. 134, 179-80 (2005)

revision of Part 2 in January 2004.[7] Therefore, precedents under the former Section 2.749 are applicable to motions for summary disposition under the current provisions in 10 C.F.R. §§ 2.710 and 2.1205.

The Commission has held that motions for summary disposition under Section 2.749 are analogous to summary judgment motions under Rule 56 of the Federal Rules of Civil Procedure, and should be evaluated by the same standards.[8] As held by both the courts and the former NRC Atomic Safety and Licensing Appeal Board, summary disposition is not simply a "procedural shortcut"; rather, it is designed "to secure the just, speedy and inexpensive determination of every action," and should be granted when appropriate.[9] In fact, 10 C.F.R. § 2.710(d)(1) authorizes a Board to consider a summary disposition motion if "its resolution will serve to expedite the proceeding if the motion is granted." In this case, summary disposition on Citizens' only admitted contention would terminate the proceeding.[10]

Pursuant to both NRC and federal case law, the party seeking summary disposition must show the absence of a genuine issue as to any material fact.[11] In response, the party opposing the motion must set forth *specific facts* showing that there is a genuine issue.[12] To be considered a genuine issue of material fact, "the factual record, *considered in its entirety*, must be enough in doubt so that there is a reason to hold a hearing to resolve the issue."[13] Bare assertions or general

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7 69 Fed. Reg. at 2227.

8 *Advanced Med. Sys., Inc.* (One Factor Row, Geneva, Ohio 44041), CLI-93-22, 38 N.R.C. 98, 102 (1993).

9 *Celotex Corp. v. Catrett*, 477 U.S. 317, 327 (1986) (citations omitted); *see also La. Enrichment Servs. L.P.* (National Enrichment Facility), CLI-06-15, 63 N.R.C. 687, 700 (2006) (affirming Board grant of summary disposition); *Advanced Med. Sys., Inc.*, 38 N.R.C. 98; *Tenn. Valley Auth.* (Hartsville Nuclear Plant, Units 1A, 2A, 1B, and 2B), ALAB-554, 10 N.R.C. 15, 19 (1979).

10 On February 6, 2007, Citizens submitted one additional proposed contention. Even if the Board were to admit this or another contention, the grant of summary disposition on Citizens' admitted contention would clearly reduce the number of issues to be decided and expedite the proceeding.

11 *See Adickes v. Kress & Co.*, 398 U.S. 144, 157 (1970); *Advanced Medical Systems, Inc.*, 38 N.R.C. at 102.

12 *See* 10 C.F.R. § 2.710(b).

13 *Cleveland Elec. Illuminating Co.* (Perry Nuclear Power Plant, Units 1 and 2), LBP-83-46, 18 N.R.C. 218,
(footnote continued)

denials are insufficient to oppose a motion for summary disposition,[14] as are mere "quotations from or citations to [the] published work of researchers [or experts] who have apparently reached conclusions at variances with the movant's affiants."[15]

Furthermore, if the party opposing the motion fails to controvert any material fact, then that fact will be deemed admitted.[16] If the moving party makes a proper showing, and the opposing party does not show that a genuine issue of material fact exists, then the Licensing Board may summarily dispose of the contention on the basis of the pleadings.[17]

The existence of conflicting expert testimony does not preclude summary disposition.[18] First, the expert witness/affiant must be competent to testify to the matters stated in the affidavit.[19] The Licensing Board may look at whether the witness qualifies as an expert by "knowledge, skill, experience, training, or education."[20] Second, the Board "must focus on whether the expert opinions are sufficiently grounded upon a factual basis."[21] As such, the nonmoving party cannot defeat summary disposition by presenting "subjective belief or unsupported speculation,"[22] or improperly supported expert opinion.[23] Thus, in opposing

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223 (1983) (emphasis added).

[14] *See* 10 C.F.R. § 2.710(b); *Advanced Med. Sys., Inc.*, 38 N.R.C. at 102; *Houston Lighting and Power Co.* (Allens Creek Nuclear Generating Station, Unit 1), ALAB-629, 13 N.R.C. 75, 78 (1981).

[15] *Carolina Power & Light Co.* (Shearon Harris Nuclear Plant, Units 1 and 2), LBP-84-7, 19 N.R.C. 432, 435-36 (1984); *see also United States v. Various Slot Machines on Guam*, 658 F.2d 697, 700 (9th Cir. 1981) (holding that "in the context of a motion for summary judgment, an expert must back up his opinion with specific facts" in an affidavit).

[16] *See* 10 C.F.R. § 2.710(a); *Advanced Med. Sys., Inc.*, 38 N.R.C. at 102-3.

[17] *N. States Power Co.* (Prairie Island Nuclear Generating Plant, Units 1 and 2), CLI-73-12, 6 A.E.C. 241, 242 (1973), *aff'd sub. nom. BPI v. AEC*, 502 F.2d 424 (D.C. Cir. 1974).

[18] *See Duke Cogema Stone & Webster* (Savannah River Mixed Oxide Fuel Fabrication Facility), LBP-05-04, 61 N.R.C. 71, 80-81 (2005) ("DCS").

[19] 10 C.F.R. § 2.710(b).

[20] *DCS*, LBP-05-04, 61 N.R.C. at 80, *citing* Fed. R. Evid. 702.

[21] *Id* at 81.

[22] *Id.* at 80 (quoting *Daubert v. Merrell Dow Pharmaceuticals, Inc.,* 509 U.S. 579, 589-90 (1993)).

[23] *Id.* at 81.

summary disposition, "expert opinion is admissible only if the affiant is competent to give an expert opinion and only if the factual basis for that opinion is adequately stated and explained in the affidavit."[24]

As discussed below, Citizens' contention is the type of contention for which no evidentiary hearing is necessary because it is based on speculation, a misinterpretation of the "local area" average thickness criterion, and simple errors in math. "To oppose . . . summary disposition, mere bare assertions, even assertions by an expert, without a fully explained factual basis are insufficient to create a genuine and material factual dispute."[25] Accordingly, the contention can be readily and expeditiously resolved in AmerGen's favor through summary disposition.

B. Standards for License Renewal

The basic standards governing the issuance of renewed licenses for operating commercial nuclear power plants are set forth in 10 C.F.R. §§ 54.21 and 54.29. The former requires AmerGen to demonstrate "that the effects of aging will be *adequately managed* so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation."[26] The latter, as applied to the OCNGS drywell, requires the NRC to determine that AmerGen has identified and has or will take action to manage the effects of aging during the period of extended operation on the functionality of the drywell, so that there is "*reasonable assurance* that the activities authorized by the renewed license will continue to be conducted in accordance with the [current licensing basis ("CLB")], and that any changes made to the plant's

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24 *Id.*

25 *Id.* at 100.

26 10 C.F.R. § 54.21(a)(3) (emphasis added).

CLB . . . are in accord with the Act and the Commission's regulations."[27] Both regulations thus require "reasonable assurance" that the effects of aging will be "adequately managed."[28]

Finally, AmerGen is required to establish an overall Aging Management Program ("AMP") that provides reasonable assurance that the effects of aging are effectively managed such that the drywell will perform its intended function during the period of extended operation. consistent with the CLB. AmerGen has defined an AMP for the drywell whose *purpose* is to do just that. AmerGen's AMP for the drywell shell is based upon American Society of Mechanical Engineers ("ASME") Code Section XI, Subsection IWE for steel containments (Class MC), in accordance with the provisions of 10 C.F.R. § 50.55a.[29] Section XI, Subsection IWE is approved for use by the NRC in 10 C.F.R. § 50.55a and, therefore, is not subject to challenge in this proceeding.[30]

While Citizens' contention challenges only the frequency of AmerGen's planned UT of the sand bed region, that UT is only a *part* of AmerGen's overall AMP. Citizens' contention fails to account for the remainder of AmerGen's AMP for managing corrosion. So long as AmerGen's AMP for managing corrosion in the sand bed region, taken as a whole, provides the requisite reasonable assurance, AmerGen satisfies the applicable requirements of 10 C.F.R. Part 54.

As demonstrated below, AmerGen's AMP satisfies Part 54 and, accordingly, summary disposition is appropriate.

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27 10 C.F.R. § 54.29(a) (emphasis added).

28 Citizens' contention argues that a worst case projection of corrosion is needed, when there is no support for that either factually or legally. There is no regulatory basis for Citizens' demand.

29 Motion for Leave to Add Contentions and Motion to Add Contentions (Dec. 20, 2006) ("December 20 Motion to Add Contentions"), Exh. ANC-1 at 49 ("LRA Supplement").

30 *See AmerGen Energy Co., LLC* (License Renewal for Oyster Creek Nuclear Generating Station) LBP-06-22 (slip op. at 24) (Oct. 10, 2006) ("LBP-06-22").

III. THE SCOPE OF THE ADMITTED CONTENTION

A. The Contention and its Bases

Citizens' contention as admitted by the Board states:

> AmerGen's scheduled UT monitoring frequency in the sand bed region is insufficient to maintain an adequate safety margin.[31]

The Board explained Citizens' argument as follows:

> Citizens argue that – because the corrosion rate in the sand bed region is unknown due to the uncertain corrosive environment – AmerGen's proposed plan to perform UT tests prior to the period of extended operation, two refueling outages later, and thereafter at an appropriate frequency not to exceed 10-year intervals, is insufficient to maintain an adequate safety margin.[32]

The admitted contention is, therefore, limited to the frequency of UT measurements of the sand bed region of the OCNGS drywell shell.[33] The "foundation" of Citizens' argument is that "UT measurements must be taken at least annually because the historical corrosion rate has been such that, if corrosion were to resume at that rate, the safety margin would be eliminated within two years."[34] The only "bases" for Citizens' contention, as explained by the Board,[35] are:

1. "the drywell shell is 0.026 inches or less from violating AmerGen's acceptance criteria";

2. "[u]nder corrosive conditions, long-term corrosion rates of more than 0.017 inches per year have been observed";

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[31] *Id* at 9.

[32] *Id* at 15.

[33] Citizens attempted to expand the scope of the litigation beyond the frequency of UT measurements on several occasions, to regions of the drywell shell above and below the sand bed region, as well as to other components within the scope of AmerGen's AMP. *See id.* at 5-6; *AmerGen Energy Co., LLC* (License Renewal for Oyster Creek Nuclear Generating Station). LBP-06-11, 63 N.R.C. 399, 393-94 (Mar. 22, 2006) ("LBP-06-11"). The Board, however, rejected these attempts. *See* LBP-06-22 (slip op. at 5-6, 36); LBP-06-11, 63 N.R.C. at 393-394, 402; Memorandum and Order (Denying Citizens' Motion for Leave to Add Contentions and Motion to Add Contention) (Feb. 9. 2007) (unpublished).

[34] LBP-06-22 (slip op. at 20 n.16).

[35] *Id.* at 15, 17 (quoting Citizens' Supplement to Petition to Add a New Contention at 9, 12 (July 25, 2006) ("July 25 Supplement"), and the June 23 and July 25, 2006 Memoranda from Dr. Rudolf H. Hausler to Richard Webster, Esq.).

3. "[t]hus, if corrosive conditions are possible, a UT monitoring frequency of once per year or more would be necessary to prevent violation of the acceptance criteria";

4. "if the next scheduled UT monitoring that is to occur before the end of the licensing period shows that these safety margins have narrowed, even more frequent monitoring would be needed"; and

5. "UT monitoring is necessary even where visual inspections of the epoxy coating do not reveal that the coating has deteriorated, because corrosion may occur under the epoxy coating in the absence of visible deterioration due to non-visible holidays, or pinholes."

Throughout Citizens' Petition and Supplement,[36] and the accompanying memoranda from Dr. Rudolf Hausler, Citizens make a number of other allegations regarding the thickness of the drywell, potential corrosion rates, and future compliance with the applicable acceptance criteria. The Board did not recognize those arguments as adequate bases in LBP-06-22 and, therefore, they need not be addressed in this Motion for Summary Disposition. Accordingly, AmerGen demonstrates in Section V, below, why there is no genuine issue as to any material fact with respect to the bases that the Board recognized, and that AmerGen is entitled to a decision in its favor as a matter of law.

B. Issues Outside the Scope of the Contention

But first, because Citizens have a history of rearguing issues that the Board has explicitly precluded,[37] AmerGen lists those areas that remain outside the scope of the contention so there is no confusion about what may be litigated as part of this proceeding:

1. The upper and embedded regions of the drywell. The Board admitted Citizens' contention challenging the adequacy of AmerGen's UT monitoring frequency of the

[36] Citizens' Petition to Add a New Contention (June 23, 2006) ("June 23 Petition"); July 25 Supplement.

[37] *See e.g.,* Motion for Leave to Add a Contention and Motion to Add a Contention (Feb. 6, 2007) ("February 6 Motion to Add New Contention"); Citizens' Motion for Reconsideration of Motion to Add New Contentions or Supplement the Basis of the Current Contention and Leave to File Such a Motion (Aug. 6, 2006); December 20 Motion to Add Contentions.

drywell shell in the *sand bed region*.[38] LBP-06-22 and previous orders in this proceeding make it clear that the scope of Citizens' admitted contention is limited to the sand bed region, and thus issues related to the upper region and embedded region of the drywell are excluded from litigation.[39]

2. **The acceptance criteria for determining the minimum required thickness of the drywell.** In rejecting *every* aspect of Citizens' reformulated contention except for the frequency of AmerGen's UT monitoring in the sand bed region, the Board ruled that "any challenge to the adequacy of AmerGen's acceptance criteria should have been made at the time Citizens filed their initial Petition to Intervene. It cannot be submitted at this late juncture."[40] Thus, Citizens may not challenge the origin, derivation or adequacy of AmerGen's minimum required thickness acceptance criteria. To the extent that AmerGen demonstrates that its UT monitoring frequency is adequate to provide reasonable assurance that those acceptance criteria will continue to be satisfied during the period of extended operations, it also will have demonstrated that the frequency of UT monitoring provides "an adequate safety margin," and answered the allegations in the contention.

3. **The monitoring programs for moisture and coating integrity.** The adequacy of AmerGen's moisture monitoring program may not be litigated.[41] This includes AmerGen's Protective Coating Monitoring and Maintenance Program ("PCMMP") and AmerGen's plans for

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38 LBP-06-22 (slip op. at 9).

39 *See* LBP-06-07, 63 N.R.C.188, 216 n. 27 (2006) (limiting Citizens' original contention of omission to the sand bed region); *AmerGen Energy Co., LLC* (License Renewal for Oyster Creek Nuclear Generating Station), LBP-06-16, 63 N.R.C. 737, 744 (2006) ("LBP-06-16") (allowing Citizens to file a new contention "raising a specific substantive challenge to AmerGen's new periodic UT program for the sand bed region" and directed that "the substance of [the new contention] must be limited to the sand bed region").

40 LBP-06-22 (slip op. at 14).

41 *Id.* at 25.

periodic visual inspections of the epoxy coating on the exterior of the sand bed region of the drywell.[42]

4. **AmerGen's response to any wet conditions and coating failure.** The Board ruled that this aspect of Citizens' contention "effectively challenges the adequacy of AmerGen's PCMMP," and that since "AmerGen has committed" to an ASME Section XI, Subsection IWE compliant program, "Citizens are prohibited from challenging its adequacy."[43]

5. **Where UT measurements are taken.** Citizens alleged, in their reformulated contention, that the spatial scope of AmerGen's UT monitoring was insufficient to systematically identify and sufficiently test all the degraded areas in the sand bed region.[44] The Board rejected Citizens' untimely challenge to the spatial scope of AmerGen's UT monitoring regime because information regarding when and where UT measurements would be taken was available long before they submitted their new petition. Thus, "the appropriate time for a challenge by Citizens to the spatial scope of AmerGen's UT measurements was promptly after AmerGen docketed its December commitment."[45]

6. **The quality assurance program for UT measurements.** The Board ruled that the adequacy of AmerGen's quality assurance program for UT measurements is not admissible noting, among other things, that "a licensee's quality assurance program is excluded from license renewal review" and that "Citizens' attack on AmerGen's quality assurance program is outside the scope of this proceeding."[46]

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[42] *Id.* at 23.

[43] *Id.* at 26, 27.

[44] *Id.* at 28.

[45] *Id.* at 30.

[46] *Id.* at 32, 33.

7. **The way AmerGen analyzes UT measurements.** Finally, the Board held that AmerGen's "statistical techniques" and methodology for determining a corrosion rate are inadmissible and outside the scope of the contention.[47]

IV. RELEVANT TECHNICAL BACKGROUND AND CORRECTIVE ACTIONS

What follows next is a brief summary of the facts relevant to historical corrosion of the OCNGS drywell shell. This background is necessary to understand why the bases supporting the admitted contention are supported by only speculation, a misinterpretation of the "local area" average thickness criterion, and simple errors in math.

A. Physical Layout

The OCNGS drywell shell is a steel pressure vessel in the shape of an inverted light bulb, with a spherical lower section and a cylindrical upper section located inside the Reactor Building. Exhibits 1 and 2 depict the drywell shell and show, in particular, the sand bed region. The drywell shell has a bottom elevation of 2' 3" and a top elevation of about 100'.[48] It is embedded in concrete on both sides from its bottom until elevation 8'11".[49] From there until elevation 11'0" (beneath the torus vent headers) and elevation 12'3" (areas between the torus vent headers), the shell is embedded in concrete only on the interior.[50]

The region of the drywell relevant to the admitted contention is located between approximately elevation 8'11" and 12'3". The floor of the sand bed region is located at approximately elevation 8'11" and is concrete.[51] Five drains, located within this concrete floor, are designed to drain any water that might reach the floor. The area adjacent to the exterior side

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47 *Id.* at 33-36.

48 *See* ACRS Info. Package at 3-1. All elevations are reported relative to mean sea level.

49 *See id.*

50 *Id.*

of the drywell shell in this area was filled with sand and, although the sand was removed about 15 years ago, this area is still called the "sand bed" region. This region of the shell is spherical and is divided into ten "bays" by the torus vent headers that connect the interior of the drywell to the torus.[52]

B. OCNGS Identified the Problem and Fixed It

In 1980, water was observed coming from the sand bed drains.[53] The source of the water was subsequently confirmed to be leakage through small cracks in the reactor cavity liner. This leakage occurred only during refueling, when the reactor cavity was flooded, and should have been collected by a concrete trough and 2" drain pipe located beneath the refueling cavity bellows. The amount of water, however, was greater than the capacity of the trough and drain pipe. Furthermore, because the curb of the trough did not contain the water, the water instead flowed into the gap between the exterior of the drywell shell and the concrete shield wall, down to the sand bed region. Exhibit 1 shows the general location of the refueling cavity, the drywell shell, and the concrete shield wall.

Five floor drains are designed to remove any water that might reach the sand bed region. However, not all of these drains historically performed as designed because they were either blocked or partially clogged. Also, the sand bed concrete floor in some bays was found to be unfinished, resulting in drains being located above the floor elevation.

The presence of corrosion-promoting water, elevated operating temperature, and sand (acting to keep the water in contact with an uncoated drywell shell) caused corrosion of the exterior of the drywell shell prior to the implementation of corrective actions. The corrosion was

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51 Exhibit 1. The surface of the floor in some of the bays was repaired with epoxy.

52 The bays are designated only with odd numbers, from 1 through 19.

53 *Id.* at 1-2, 2-1, 4-1. This historical overview can be found in the LRA, the LRA supplement, and the ACRS February 1, 2007 transcript.

not, however, evenly distributed either among or within the ten bays. In general, corrosion was greatest in the vicinity of the torus vent headers and not in the middle of the bay. In addition, corrosion was greatest near the air-water interface located near the top of the sand bed region, between approximately elevations 11' and 12'. This area has been referred to as the "bath tub ring" of corrosion. For reference, the as-designed thickness of the drywell shell in the sand bed region was 1.154". The uneven distribution of corrosion resulted in a maximum general average metal loss of about 0.35" in part of Bay 19, and almost no metal loss in Bay 3.[54] The maximum observed corrosion rate prior to 1992 was near 0.040" per year.[55]

Corrective actions initiated in the late 1980s and early 1990s to prevent additional corrosion of the exterior drywell shell in the sand bed region included:

- applying metal tape and a strippable coating to the reactor cavity, prior to flooding for refueling outages, to reduce the amount of water leaking through the liner to at least below the capacity of the 2" drain line below the bellows;[56]
- repairing the concrete curb below the refueling bellows to ensure that any water that reaches this area is directed to the 2" drain line;
- removing the sand from the sand bed region;
- repairing and finishing the concrete floor in those bays in the sand bed region that were unfinished, to ensure any water that entered that region would be directed to the sand bed drains;
- clearing the five sand bed drains;
- removing the corrosion products from the exterior of the drywell shell in the sand bed region; and
- coating the exterior of the drywell shell in the sand bed region with a multi-layered epoxy system (*i.e.,* one pre-primer coat, and two top coats) to prevent any water or moisture that might reach the sand bed region from contacting the exterior shell.

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54 *See* ACRS Info. Package, Table 1, at 6-2.

55 *Id.* at 6-1, 8-4.

56 Metal tape and strippable coating were not applied during the 1994 and 1996 outages, but have been applied during each refueling outage since then.

These corrective actions have protected the exterior of the drywell shell in the sand bed region from further corrosion. Accordingly, corrosion of the exterior of the drywell shell in the sand bed region has been arrested.

C. Recent Monitoring Confirmed that Corrective Actions are Adequate

AmerGen collected data during the October 2006 refueling outage which demonstrate that the corrective actions identified above are effective at preventing water from reaching the sand bed region, and protecting the drywell shell in the sand bed region.[57] Specifically, AmerGen confirmed that no water leaked to the sand bed region through monitoring of the refueling trough drain and the five sand bed drains, as well as through visual inspection of the sand bed floor and drywell shell in all ten bays.

AmerGen also performed VT-1 (*i.e.,* visual) inspections of the epoxy coating in all ten bays in the sand bed region in accordance with ASME Section XI IWE. The VT-1-qualified inspectors did not identify *any* defects or deterioration of the epoxy coating. These visual inspections confirm that corrosion of the external drywell shell in the sand bed region remains arrested. AmerGen also took internal and external UT measurements of the drywell shell in all ten bays in the sand bed region: it took internal measurements from the 19 "grids" located at about elevation 11'3", which were measured in 1992, 1994, and 1996; and it took external measurements from approximately 100 "points" at various elevations throughout the ten bays, which were last measured in 1992. There are no statistically-significant differences between the current and previous data, further confirming that corrosion in this area has been arrested.[58]

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57 Leakage can only occur during refueling outages when the reactor cavity is flooded to facilitate moving fuel. AmerGen currently refuels OCNGS every two years.

58 Citizens recently argued that the 2006 data are significantly different from the 1992 data. *See* February 6 Petition to Add New Contention. As explained in AmerGen's March 5, 2007 Answer, there is no genuine dispute of material fact on that issue. *See also* conversation between S. Armijo, ACRS member, and R. Webster at the February 1, 2007 ACRS meeting. Tr. at 262-63 (Feb. 1, 2007) ("Independently, I did something very similar to what Mr. Licina did, and . . . I saw the same phenomena . . . . [T]here are systematic changes, systematic bias and there was no way I could conclude that there was continuing

(footnote continued)

D. Commitments Relevant to the Contention

AmerGen's AMP must provide reasonable assurance that the effects of aging will be adequately managed so that the intended functions of the drywell will be maintained consistent with the CLB for the period of extended operation.[59] As part of its AMP, AmerGen has committed to perform inspections of the drywell shell. A full list of the docketed commitments related to the AMP for the drywell shell are provided in Exhibit 3.[60] For the sand bed region, which is the only region relevant to the admitted contention, these include visual inspections of the epoxy coating that protects the exterior of the drywell shell in all ten bays, every other refueling outage (*i.e.,* every four years). These commitments also include internal and external UT measurements of the drywell shell in all ten bays in the sand bed region every other refueling outage.

At the time the Board admitted this contention, the Board characterized AmerGen's commitment as performing UT tests prior to the period of extended operation, two refueling outages later, and thereafter at an appropriate frequency not to exceed 10-year intervals.[61] As shown in Exhibit 3, AmerGen has since modified its UT frequency commitment so that it will perform UT measurements during the refueling outage in 2008, and then every other refueling outage thereafter (*i.e.*, every four years), using the same internal grid locations and the more than 100 external "points" that it measured during the 2006 refueling outage.

AmerGen's AMP commitments provide a "safety net" should unanticipated rates of corrosion be found during any refueling outage. In particular, if statistically-significant deviations from the prior UT results are found, AmerGen will take additional measurements to

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corrosion, that the most reasonable interpretation of the data is that the corrosion had been arrested since 1992.").

[59] 10 C.F.R. §§ 54.29 and 54.21; *see* discussion in Section II.B., above.

[60] In some cases, these commitments already have been completed.

confirm the readings, promptly notify the NRC, conduct additional visual inspections, perform additional engineering evaluations, and perform an operability determination *prior to restart from the associated outage*. Clearly, these commitments provide reasonable assurance that, if unanticipated conditions are found, the plant will not be restarted without a determination, subject to review and concurrence by the NRC Staff, that the applicable acceptance criteria are satisfied. Furthermore, AmerGen's commitment necessarily includes the obligation to conduct more frequent UT thereafter if the established corrosion rates so warrant.

V. CITIZENS HAVE FAILED TO IDENTIFY ANY GENUINE ISSUE OF MATERIAL FACT

A. Introduction

The intended functions of the drywell are to serve as both structural support (*i.e.*, to prevent buckling) and as a pressure boundary.[62] Before the sand was removed from the sand bed region in 1992, GE performed an engineering analysis of the Oyster Creek drywell shell to determine whether historical corrosion prevented the drywell from performing its intended functions. GE conducted this analysis in 1991, based on ASME Code requirements, to establish the minimum required general thickness, with the sand removed, for both pressure and buckling stresses.[63]

The results of GE's analysis show that the minimum required thickness in the sand bed region is controlled by buckling. Moreover, a general thickness acceptance criterion of 0.736" will satisfy ASME Code requirements with a safety factor of 2.0 against buckling for the controlling refueling load combination, and 1.67 safety factor for the post-accident load

[61] LBP-06-22 (slip op. at 14).

[62] LRA Supplement at 4-5.

[63] ACRS Info. Package at 6-7.

combination (*i.e.*, flooding of the containment).[64] Accordingly, UT measurements thicker than 0.736" are accepted without further evaluation.

If any local UT measurements reveal a thickness below 0.736", AmerGen performs a separate evaluation to confirm that the locally-thin areas, in the as-found condition, meet the ASME Code. Specifically, locally-thinned areas are evaluated, among other things, against a minimum local average thickness of 0.536" over an area not to exceed one square foot, with a surrounding one-foot transition area to 0.736", such that the total area with thickness below 0.736" is nine square feet.[65] Figure 1 attached to the Affidavit of Mr. Pete Tamburro visually depicts this local area acceptance criterion. There is also a "very local" area average thickness of 0.490" over an area not to exceed 2.5 inches in diameter.[66]

As demonstrated below, the admitted contention is based on a misunderstanding of this local area acceptance criterion, followed by impermissible speculation and mathematical errors. AmerGen discusses each basis for Citizens' contention and demonstrates that Citizens have failed to raise any genuine issues of material fact. Accordingly, AmerGen is entitled to a decision in its favor as a matter of law.

B. Citizens' Allegation that the Drywell Is 0.026 Inches From Violating AmerGen's Acceptance Criteria Presents No Genuine Issue of Material Fact

The Board has stated that, according to Citizens, "'the drywell shell is 0.026 inches or less from violating AmerGen's acceptance criteria'."[67] This allegation does not raise a genuine issue of material fact because, as explained below and in the attached Affidavit of Mr. Peter Tamburro, it is based on speculation, a misinterpretation of the 0.536" local area average

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64 *See id* at 6-8.

65 *See id.* at 6-8, 6-18. *See also* Citizens' June 23 Petition, Exh. NC3, at 4-6. Also, as discussed in Section III.B. above, the Board has ruled that any challenge to the adequacy of those acceptance criteria is beyond the scope of the admitted contention.

66 *Id.*

67 LBP-06-22 (slip op. at 15).

thickness criterion, and simple errors in math. Such bases are ripe for rejection under the standards of summary disposition.[68]

The sole support offered by Citizens in their June 23 Petition and July 26 Supplement for their first allegation is the memorandum from Dr. Hausler which is appended to Citizens' June 23 Petition ("June 23 Hausler Memorandum"). In that memorandum, Dr. Hausler states:[69]

> Applying the one square foot below 0.736 inches acceptance criterion . . . , the total area measured below 1 square foot was around 0.3 square feet. However, this area is <u>very sensitive to additional corrosion</u> because in a length of around 5 inches, the thickness changed from around 0.736 inches to 0.800 inches. Assuming that the edge of the hole is a straight line, this means that a change of 0.064 inches in depth occurs over about 5 inches in length. Thus, for the radius of the thin area to change by two inches, the depth <u>would have to change</u> by only 0.026 inches. <u>If this occurred</u> the total area below 0.736 inches would be approximately 1.6 square feet, well beyond the current acceptance criterion. <u>Assuming a worst case corrosion rate</u> of 0.020 inches per year shows that the area acceptance criterion could be violated in around a year, even if the thin areas have not grown bigger since they were last measured in 1992.

First, from the underlined parts of the quote above, it is clear that Dr. Hausler is speculating about what could happen to the drywell shell as opposed to what has happened. This speculation about future corrosion is unsupported by current data and amounts merely to Dr. Hausler's hypothetical musings. Such speculation does not survive summary disposition.[70]

Second, as Peter Tamburro demonstrates in Paragraphs 9-18 of his Affidavit, Dr. Hausler misinterprets the acceptance criteria. The first criterion is a *general* average thickness of 0.736". An area of average thickness less than 0.736" remains adequate from a buckling perspective if it

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[68] *See DCS* , 61 N.R.C. at 81 (the Board "must focus on whether the expert opinions are sufficiently grounded upon a factual basis").

[69] June 23 Hausler Memorandum at 7 (emphasis added).

[70] *See DCS*, 61 N.R.C. at 81.

meets the 0.536" *local area* average thickness criterion.[71] Dr. Hausler's discussion assumes that the *local area* criterion is violated if the area below 0.736" is greater than *one* square foot.[72]

Dr. Hausler's interpretation of the local area acceptance criterion is incorrect. He appears to apply that criterion with an abrupt step-change (like a cliff) on all sides of the one square foot area that averages 0.536", such that the thickness increases to 0.736" with no transition.[73] However, AmerGen evaluates locally-thinned areas against, among other things, a minimum local average thickness of 0.536" over an area not to exceed one square foot, with a surrounding one-foot *transition area* to 0.736", such that the total area with thickness below 0.736" is *nine square feet*.[74] Figure 1 attached to Mr. Tamburro's affidavit depicts this local area acceptance criterion. (Citizens are now aware of this transition area.[75]) Thus, even if Dr. Hausler's speculation that there could in the future be an area of approximately 1.6 square feet below 0.736" is correct—which it is not—then the local area acceptance criterion still would not be violated because that criterion allows for an area thinner than 0.736" of nine square feet. Dr. Hausler's misinterpretation and misunderstanding of the criterion in no way creates a genuine issue of material fact requiring a hearing.

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71 *See, e.g.,* Citizens' Exh. NC3, at 5-6.

72 *See* June 23 Hausler Memorandum at 7 ("If this occurred the total area below 0.736 inches would be approximately 1.6 square feet, well beyond the current acceptance criterion").

73 Tamburro Affidavit, ¶ 20.

74 *See* ACRS Info. Package at 6-8, 6-18, discussing GE analyses. *See also* Citizens' June 23 Petition, Exh. NC3, at 4-6; *id.* at 6 ("These [GE] studies contain analyses of the drywell . . . reducing the [0.736"] thickness by 0.200 inches in an area 12 x 12 inches in the sandbed region, tapering to original thickness over an additional 12 inches"). AmerGen applies 0.536" and its transition area to 0.736" as a local area acceptance criterion in its calculations, taking into account the location, configuration, etc. of the locally thinned areas. Tamburro Affidavit, ¶ 20; *see also.,* Exhibit 3 to "AmerGen's Answer Opposing Citizens' February 6, 2007 Motion for Leave to Add a Contention and Motion to Add a Contention" (March 5, 2007) (the "24 Calc.").

75 *See* Citizens' February 6 Motion to Add New Contention at 5. ("GE modeled an area of one square foot with a thickness of 0.536 inches, surrounded by a one square foot transition zone back to 0.736 inches . . . ").

Contrary to Citizens' allegations, there is quite a bit more than 0.026" margin remaining before the ASME Code is exceeded. The bounding general average thickness in the sand bed region is 0.800" located in Bay 19, which leaves a margin of 0.064" when compared to the 0.736" general area thickness criterion (*.i.e.,* 0.800"-0.736").[76] The bounding local area average thickness Dr. Hausler identified is 0.618" in Bay 13, which leaves a margin of 0.082" when compared to the 0.536" local area thickness criterion (*.i.e.,* 0.618"-0.536").[77]

For all these reasons, only speculation and a misinterpretation of the acceptance criterion support Citizens' assertion that only 0.026" remains before the acceptance criteria are exceeded. Accordingly, this first basis does not raise a genuine issue of material fact. Mr. Tamburro, in Paragraphs 24-33 of his Affidavit, also explains that Dr. Hausler's allegations are based on mathematical errors which similarly do not raise a genuine issue of material fact. The Board, however, need not delve into Mr. Tamburro's additional explanation about Dr. Hausler's math errors to dismiss the contention because Mr. Tamburro's explanation is in addition to Dr. Hausler's misinterpretation and misunderstanding of the local area acceptance criterion which is, by itself, enough for the Board to now reject the contention.

C. Citizens' Allegation that, Under Corrosive Conditions, Long-Term Corrosion Rates of More Than 0.017 Inches Per Year Have Been Observed, Fails to Present a Genuine Issue of Material Fact

The next basis statement is that "[u]nder corrosive conditions, long-term corrosion rates of more than 0.017 inches per year have been observed."[78] The source of this statement is

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[76] *See* ACRS Info. Package, Table 1, at 6-2. All the other bays have greater margin, ranging from 0.074" in Bay 17, to 0.439" in Bay 3. *See id.*

[77] Tamburro Affidavit, ¶ 43. Citizens' also stated that AmerGen has "reported that over 20 areas in the sand bed region are now thinner than 0.736 inches and these areas have an average thickness of 0.703 inches." June 23 Petition at 3. While there are approximately 20 individual UT "point" measurements that are below 0.736", *see* ACRS Info. Package, Table 2, at 6-12, the existence of these points does not raise a genuine issue of material fact. As discusses above, if any local UT measurements reveal a thickness below 0.736", AmerGen performs a separate evaluation to confirm that the locally-thin areas, in the as-found condition, meet the ASME Code using a local average thickness of 0.536".

[78] July 25 Supplement at 9.

Dr. Hausler's June 23 memorandum, which relies on a public AmerGen document for the proposition that "[t]he second highest long term corrosion rate estimated [by AmerGen historically] was 0.017 inches per year."[79] This statement is unsupported as applied to current or future corrosion and, thus, fails to create a genuine issue of fact or law requiring a hearing.[80]

Dr. Hausler's opinions regarding a 0.017" per year corrosion rate are strikingly similar to the opinions of the intervenor's expert in the Construction Authorization proceeding for the Mixed-Oxide Fuel Fabrication Facility, which a Licensing Board rejected on summary disposition in 2005.[81] In that case, the intervenor's expert argued that a 7.0-plus magnitude earthquake could occur close enough to affect the facility and, therefore, that the applicant should have included such a large earthquake in the facility's design spectra.[82] That Board granted summary disposition in the applicant's favor, finding, in part, that the intervenor's expert "fail[ed] to provide a factual foundation for his assertion that such an earthquake could occur."[83] The Board concluded that "[t]o oppose summary disposition, mere bare assertions, even assertions by an expert, without a fully explained factual basis are insufficient to create a genuine and material factual dispute."[84] Here, Dr. Hausler opines that a corrosion rate of 0.017" per year is possible, without any factual support. Citizens essentially ask the Board to assume that the conditions present in the sand bed region prior to 1992 (when the sand was removed) occurred after 1992, or will occur in the future. Such a speculative, unsupported argument does not survive summary disposition.

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79 June 23 Hausler Memorandum at 6 (citing Citizens' Exh. NC1 at 20).

80 *See DCS*, LBP-05-04, 61 N.R.C. at 80-81.

81 *See id.* at 100.

82 *Id.*

83 *Id.*

84 *Id.*

There are a myriad of reasons why an allegation of a current or future corrosion rate of 0.017" per year does not raise a genuine issue of material fact. First, this rate is solely historical as demonstrated by the basis statement's use of past tense, and AmerGen's document which is the source of the statement. Unsupported speculation that past corrosion rates can occur in the future does not raise a genuine issue of material fact.[85]

Second, Dr. Hausler can only speculate that this rate of corrosion could occur in the future on the exterior of the drywell shell in the sand bed region. The corrective actions identified in Section III.A., above, demonstrate why such a rate in that region is not reasonable. The source of water—the flooded reactor cavity liner during refueling outages—has been identified and controlled such that this water is no longer expected to reach the sand bed region when a strippable coating is applied to the refueling cavity liner prior to refueling outages.

Even if some water did reach the sand bed region it would not have the effect after 1992 that it would have had before that time. As Mr. Barry Gordon explains in Paragraph 13 of his Affidavit, part of the reason why the corrosion rate was historically as high as 0.017" per year in certain bays of the drywell shell sand bed region is because there was a medium (*i.e.*, sand) to physically hold water against the drywell shell. The sand has been removed so there is no water-retaining media to facilitate future corrosion.

Third, Dr. Hausler ignores the fact that the historic corrosion occurred because the drywell shell in the sand bed region was <u>not</u> coated. The exterior shell is now protected by a three-layer epoxy coating. As Jon Cavallo states in Paragraph 12 of his Affidavit, this coating system was designed for submerged applications, such as tank bottoms, so even if water was always present in the sand bed region, it would have no effect on the coated steel shell.[86]

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85 *See id.* at 88 (finding that Intervenor's expert failed to provide a scientific explanation for his allegation).

86 It is not clear that Dr. Hausler is qualified to challenge Mr. Cavallo's affidavit. An affiant must be competent to testify to the matters stated in the affidavit. *See* 10 C.F.R. § 2.710(b). Although the Board

(footnote continued)

Fourth, if a corrosion rate of 0.017" per year had occurred between 1992 and 2006, then it would have been readily detected by the VT-1 (visual) and UT performed during the 2006 refueling outage. Based on the information contained in the VT-1 inspection reports generated for the coating in all ten external drywell bays during the October 2006 outage, the epoxy coating is in good condition with no defects or deterioration.[87] The UT measurements collected from both the interior and exterior of the drywell shell did not identify a corrosion rate of 0.017" per year. Such a rate would have resulted in a loss of 0.238" (0.017" per year x 14 years), which is well within the expected equipment measurement error of 0.020".[88]

Fifth, even if there was a 0.017" per year corrosion rate, Citizens have only argued that it would be localized, and localized corrosion at that rate does not create a genuine issue of material fact. Specifically, Citizens, through Dr. Hausler, speculate that there might be tiny holes ("pinholes" or "holidays") in the epoxy coating which could allow water to contact the exposed shell in the pinhole or holiday, causing corrosion.[89] Citizens necessary imply, therefore, that these hypothetical defects in the epoxy coating are material to the contention.

By definition, a pinhole or a holiday is a defect in the original application of the coating. But the possibility of this kind of defect decreases with each additional coat of epoxy applied.[90]

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has accepted Dr. Hausler as an expert relating to corrosion of the drywell shell, the Board has not accepted him as an expert relating to the performance of coatings. *See* LBP-06-22 (slip op. at 17 n.14). AmerGen believes that Citizens have not introduced information on the record to demonstrate that Dr. Hausler is qualified to present an expert opinion on the application and performance of coatings, specifically the multi-layer epoxy coating system on the exterior of the OCNGS drywell shell in the sand bred region.

87 Tamburro Affidavit at ¶ 40.

88 *Id.* at ¶ 33.

89 *See e.g.* LBP-06-22 (slip op. at 17), citing Citizens' July 25, 2006 Supplement at 12 ("Citizens also state that . . . corrosion may occur under the epoxy coating in the absence of visible deterioration due to non-visible holidays, or pinholes"); *id.* at 19, citing Dr. Hausler's Memorandum to R. Webster at (July 25, 2006) ("Hausler's July 25, 2006 Memorandum").

90 Cavallo Affidavit at ¶ 14.

The epoxy protecting the exterior of the drywell shell is comprised of a three layer (a pre-prime and two coats) coating system.[91]

In fact, Citizens' argument that such local defects have existed since 1992 is inconsistent with their argument that the air in the sand bed region is moist and capable of corrosion.[92] If a moist environment and pinholes coexisted for the past 14 years (1992 to 2006), then the resulting corrosion would be easily visible during the VT-1 inspections.[93]

Even if such tiny defects existed, Dr. Gordon explains in Paragraphs 15-18 of his Affidavit, why they would not allow materially significant corrosion behind the coating even under unrealistic conditions. Dr. Gordon assumes, among other things, that water: enters the sand bed region during a refueling outage when inspections are not performed; finds its way to a pinhole that is conveniently located over the thinnest portion of the shell; begins to corrode the underlying shell immediately at the start of the outage at a rate of 0.039" per year (more than twice the rate Citizens postulate); and does not evaporate from behind the pinhole (terminating the corrosion process) until a year later even though the operating temperature in the sand bed region is 130°F. Sufficient margin remains even under these unrealistic conditions, demonstrating that AmerGen's UT frequency is adequate.

Mr. Tamburro also explains, in Paragraphs 42 and 43 of his Affidavit, why the 0.017" per year corrosion rate that Citizens proffer does not raise a genuine issue of material fact. Corrosion behind a pinhole or holiday would be analyzed against the "very local" area acceptance criterion of 0.490" which applies to areas not to exceed 2.5 inches in diameter. The thinnest external UT point measurement identified by Dr. Hausler is 0.618", located in Bay 13. Simple math demonstrates that there is 0.128" of margin available for a pinhole or holiday in this

91 *Id.*

92 *Id.* at ¶ 19.

thinned area in Bay 13 (*i.e.,* 0.618"-0.490"), and that it would take more than seven years for this margin to disappear with a corrosion rate of 0.017" per year (*i.e.,* 0.128"/0.017 = 7.5 years"). AmerGen, however, is performing UT measurements and visual inspections of the shell in the sand bed region every four years. This frequency demonstrates that there is no genuine issue of material fact requiring a hearing.

Sixth, even if significant corrosion could occur behind a pinhole or holiday in the epoxy coating, Mr. Cavallo explains that corrosion at a rate of 0.017" per year would be visible through the VT-1 inspections performed every four years.[94] As carbon steel corrodes, the reaction between oxygen and the iron in the steel results in an iron oxide byproduct. The epoxy coating would not allow the corrosion byproducts to migrate from the site of the corrosion, so these byproducts would either accumulate as a blister at the corrosion site, or they would seep out through the postulated pinhole or holiday, onto the otherwise gray epoxy coating. In either case, the corrosion byproducts would be clearly visible in a VT-1 inspection.

The corrosion byproduct occupies a volume seven to ten times greater than the corroding steel.[95] For example, if 0.017" of steel corrodes in a year under the epoxy coating, then between 0.119" and 0.170" of byproduct would result. Four years of corrosion at that rate—the interval that AmerGen will perform UT in the sand bed region—would result in between 0.476" and 0.680" of corrosion byproduct.[96] This amount of corrosion would, therefore, cause a blister under the epoxy coating of around ½-inch.[97] Such a blister would be clearly visible by an inspector qualified to perform VT-1 inspections.

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93 *Id.*

94 *Id.* at ¶18.

95 *Id.* at ¶17.

96 *Id.*

97 To put this ludicrous alleged rate in perspective, a corrosion rate of 0.017" occurring in a pinhole since 1996 (which was the last time that strippable coating was not used during a refueling outage), would result (footnote continued)

Finally, with 0.064" average thickness remaining in the bay with the least margin (*i.e.*, Bay 19), and AmerGen performing UT and visual inspections every four years, the drywell shell in Bay 19 could tolerate an average of 0.016" per year of corrosion over an area larger than nine square feet before violating the general average thickness.[98] Such a corrosion rate, as demonstrated above, is simply speculation, and the frequency of AmerGen's visual and UT inspections make it impossible that such a condition would exist without AmerGen identifying it.[99]

For all these reasons, a corrosion rate of 0.017" per year is simply speculation about future events that cannot be supported by realistic arguments or data. Accordingly, this second basis does not raise a genuine issue of material fact.

D. Citizens' Allegation that a UT Monitoring Frequency of Once Per Year or More Is Necessary Presents No Genuine Issue of Material Fact

The Board stated that, according to Citizens, "if corrosive conditions are possible, a UT monitoring frequency of once per year or more would be necessary' to prevent violation of the acceptance criteria."[100] Again, Citizens made this statement in their Supplement (at p. 9). The apparent basis is their belief that the drywell is within 0.026" or less from violating AmerGen's acceptance criteria and, at a rate of 0.017 inches per year, the acceptance criteria would be violated in less than two years. This argument does not raise a genuine issue of material fact because, as discussed above in Section V.B. and C., the supporting allegations concerning a

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in a 1.2" to 1.7" blister in the epoxy coating. That blister conservatively would be as thick as the following dashes are wide: ----------------------------.

[98] The drywell shell would not collapse if such corrosion occurred. The acceptance criteria are based on the ASME Code which includes a safety factor of 2.0 for buckling under refueling conditions. In other words, the drywell shell would be twice as thick as it needed to be to prevent actual buckling, even under Citizens' hypothetical scenario.

[99] The eight to ten year rated lifetime discussed in Citizens' Exhibit 6 to their Original Petition is also simply incorrect. The multilayer epoxy coating is designed to withstand a submerged environment and to last for the life of the plant, provided that proper VT-1 inspections are conducted and necessary corrective maintenance is performed to address any discrepancies found. Cavallo Affidavit, ¶ 23.

0.026" or less margin, and a 0.017" per year corrosion rate do not themselves raise a genuine issue of material fact.

E. Citizens' Allegation that If the Next Scheduled UT Monitoring Shows that These Safety Margins Have Narrowed, then Even More Frequent Monitoring Would Be Needed Presents No Genuine Issue of Material Fact

The Board also stated that, according to Citizens, "'if the next scheduled UT monitoring that is to occur before the end of the licensing period shows that these safety margins have narrowed, even more frequent monitoring would be needed.'"[101] Clearly, this statement is no more than pure speculation about possible future UT results and cannot, by itself, create a genuine issue of material fact. Moreover, AmerGen performed this "next scheduled UT monitoring" in October 2006, and Citizens did not seek to amend their admitted contention to incorporate those results. Therefore, the Board can dismiss this basis statement because it is procedurally moot.[102]

In any event, the UT data—coupled with the VT-1 inspection from the October 2006 refueling outage—confirmed that corrosion on the exterior of the drywell shell has been arrested.[103]

F. Citizens' Allegation That UT Monitoring is Necessary Even Where Visual Inspections of the Epoxy Coating Do Not Reveal Coating Deterioration Presents No Genuine Issue of Material Fact

The Board stated that, according to Citizens, "'UT monitoring is necessary even where visual inspections of the epoxy coating do not reveal that the coating has deteriorated, because

[100] LBP-06-22 (slip op. at 15).

[101] *Id.; see also* Citizens' July 25 Supplement at 9.

[102] LBP-06-16, 63 N.R.C. at 745.

[103] Tamburro Affidavit at ¶ 41.

corrosion may occur under the epoxy coating in the absence of visible deterioration due to non-visible holidays, or pinholes'."[104]

This allegation fails to raise a genuine issue of material fact because, as discussed above in Section V.B., any localized corrosion beneath "pinholes" or "holidays" would be compared to the 0.490" very local area average thickness criterion, not the 0.736" general area average thickness criterion. And there is adequate thickness remaining even in the thinnest location in the thinnest bay, at the speculative 0.017" per year corrosion rate to allow for a frequency of UT or visual inspections to occur more than every four years. Because AmerGen is performing visual and UT inspections every four years, this does not raise a genuine issue of material fact.[105]

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[104] LBP-06-22 at 17; *see also* Citizens' Supplement at 12.

[105] Although cited by the Board, AmerGen believes that this concern is outside the scope of the admitted contention. Citizens allege that "corrosion could occur below the damaged coating without being observed visually" (Citizens' Supplement at 12), and that "[h]olidays and pinholes in the coating cannot be assessed by 'visual examination'" (Dr. Hausler July 25, 2006 Memorandum at 6). These allegations go to the adequacy of AmerGen's coatings monitoring program, an issue already excluded from the admitted contention by the Board.

VI. CONCLUSIONS

The only admitted contention in this proceeding is based on speculation, misinterpretation of the governing acceptance criterion, and errors in math. These bases in no way raise a genuine issue as to any material fact. The Board should, therefore, grant summary disposition in AmerGen's favor and terminate the proceeding.

Respectfully submitted,

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COUNSEL FOR
AMERGEN ENERGY COMPANY, LLC

Dated in Washington, D.C.
this 30th day of March 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

In the Matter of:	)	March 30, 2007
AmerGen Energy Company, LLC	)	
	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of "AmerGen's Motion for Summary Disposition" were served this day upon the persons listed below, by E-mail and first class mail, unless otherwise noted.

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EXHIBIT 1

AmerGen

An Exelon Company

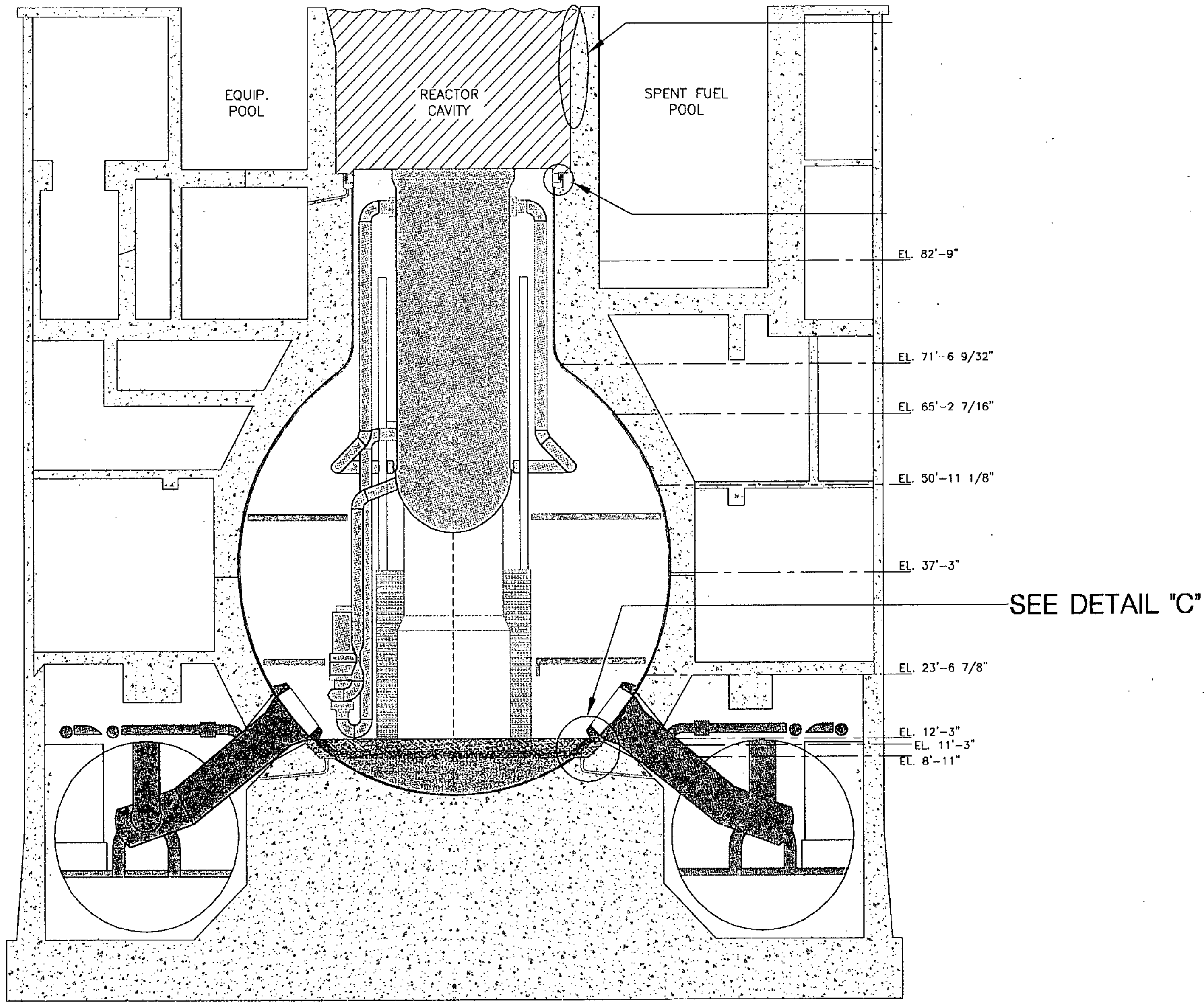

EXHIBIT 2

Exhibit 2

AmerGen
An Exelon Company

LOWER DRYWELL/SANDBED REGION DETAIL C

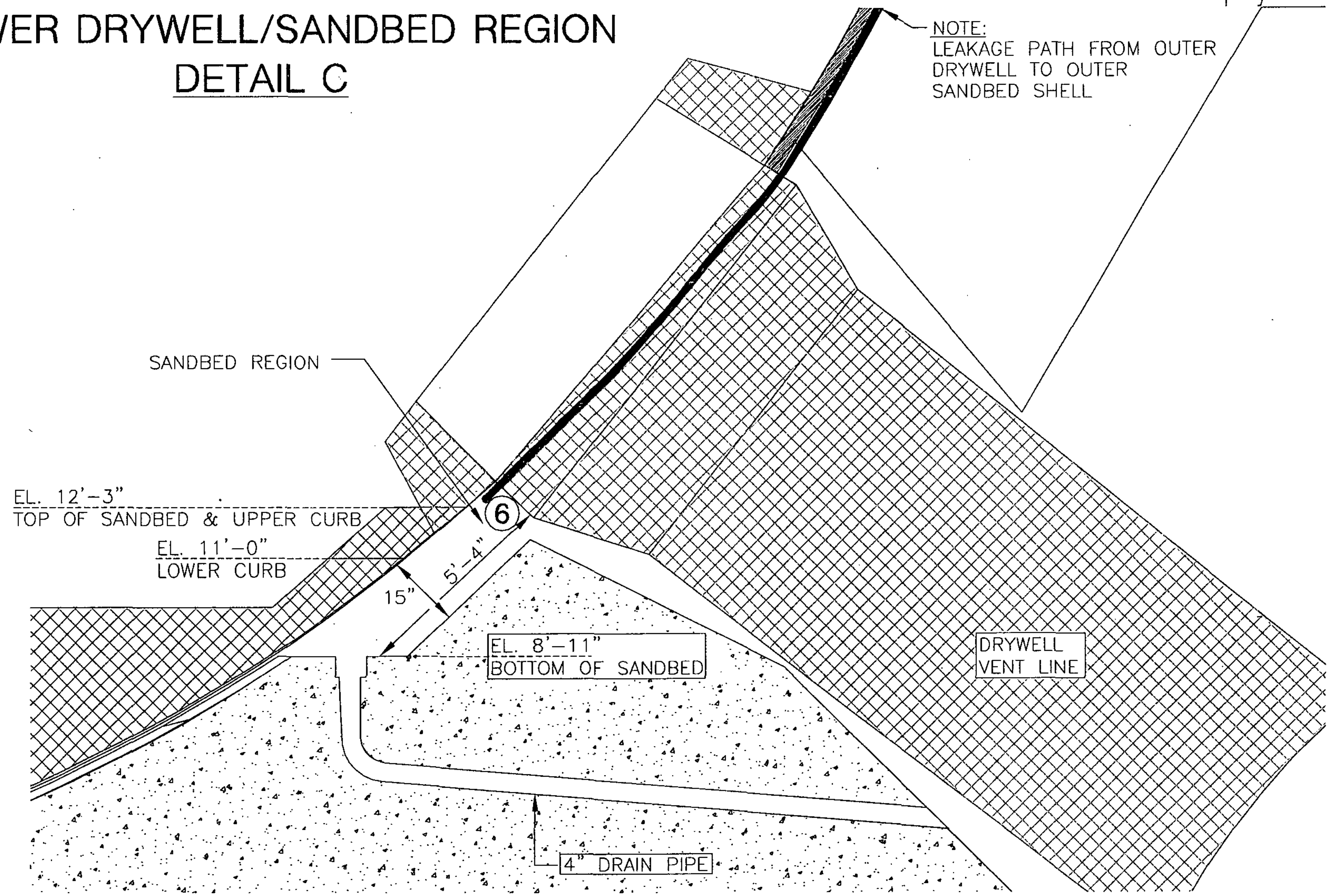

EXHIBIT 3

Exhibit 3

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10 CFR 50
10 CFR 51
10 CFR 54

2130-07-20464
February 15, 2007

U. S. Nuclear Regulatory Commission
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Washington, DC 20555

Oyster Creek Generating Station
Facility Operating License No. DPR-16
NRC Docket No. 50-219

Subject: Additional Commitments Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application (TAC No. MC7624)

References:
1. January 18, 2007 Meeting Between ACRS License Renewal Subcommittee, AmerGen Energy Company, LLC and NRC Staff, related to License Renewal of Oyster Creek Generating Station
2. February 1, 2007 Meeting Between Full ACRS, AmerGen Energy Company, LLC and NRC Staff related to License Renewal of Oyster Creek Generating Station
3. ACRS Letter Dated February 8, 2007, Describing the Outcome of the February 1, 2007 ACRS Review of the Oyster Creek Generating Station License Renewal Application

In the Reference 1 meeting, AmerGen Energy Company, LLC (AmerGen) presented detailed information related to the condition of and aging management program activities for the primary containment drywell shell, as part of AmerGen's efforts to renew the operating license for the Oyster Creek Generating Station (OCGS). The Subcommittee identified several specific issues related to the drywell shell structural analysis and certain aspects of the program proposed by AmerGen to manage aging of the drywell shell for the extended period of operation.

During the full ACRS review of the Oyster Creek License Renewal Application (LRA) in the Reference 2 meeting, AmerGen presented its proposed responses to the issues identified by the Subcommittee in the January 18, 2007 meeting. In its February 1st presentation, AmerGen made three additional commitments to address these previous Subcommittee items. This letter documents these commitments.

In addition, AmerGen is making a commitment to perform the full scope of drywell sand bed region inspections, consistent with what was performed during the 2006 refueling outage, on a frequency of every other refueling outage. AmerGen believes that this commitment is responsive to a recommendation made by NRC Staff at the February 1, 2007 ACRS meeting, which was endorsed by the ACRS in its February 8, 2007 letter to the NRC Chairman.

The details of these four new commitments are provided in the Enclosure to this letter. The ASME Section XI, Subsection IWE Primary Containment Inspection aging management program (commitment 27) is modified to include these new commitments, and to clarify the effect of these new commitments on previously made IWE program commitments.

If you have any questions, please contact Fred Polaski, Manager License Renewal, at 610-765-5935.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Executed on 02-15-07

Michael P. Gallagher

Michael P. Gallagher
Vice President, License Renewal
AmerGen Energy Company, LLC

Enclosure: Regulatory Commitments

cc: Regional Administrator, USNRC Region I
USNRC Project Manager, NRR - License Renewal, Safety
USNRC Project Manager, NRR - License Renewal, Environmental
USNRC Project Manager, NRR - Project Manager, OCGS
USNRC Senior Resident Inspector, OCGS
Bureau of Nuclear Engineering, NJDEP
File No. 05040

ENCLOSURE – REGULATORY COMMITMENTS

The following table identifies additions being made to item #27 of the License Renewal Commitment List, Table A.5 of the Oyster Creek LRA. Four commitments are being added to the ASME Section XI, Subsection IWE Primary Containment Inspection Program as part of this submittal. These new commitments are numbered to sequentially follow the commitments made in previous LRA correspondence as part of the IWE Inspection Program. The full set of commitments made as part of the IWE Program is repeated here for convenience. **Bold** font is used to highlight new information.

In addition, clarifications are made to certain previously made IWE Program commitments to indicate 1) commitments that were completed during the 2006 refueling outage and 2) the effects, if any, of the new commitments on the scope or frequency of previously made commitments. Again, **bold** font is used to highlight information introduced in this submittal.

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
27) ASME Section XI, Subsection IWE	Existing program is credited. The program will be enhanced to include: 1. Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years, except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection, to provide early confirmation that corrosion has been arrested. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the	A.1.27	Prior to the period of extended operation Prior to the period of extended operation **(completed during 2006 refueling outage); then every other refueling outage thereafter**	Section B.1.27

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	1992, 1994, and 1996 UT results will result in corrective actions that include the following: • Perform additional UT measurements to confirm the readings. • Notify NRC within 48 hours of confirmation of the identified condition. • Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected. • Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity. • Perform operability determination and justification for operation until next inspection. These actions will be completed prior to restart from the associated outage. **Note: The frequency for the inspections described in commitment 1 (above) has been changed to every other refueling outage, in accordance with commitment 21 of the IWE Inspection Program.** 2. A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded.		Refueling outages prior to and during the period of extended operation	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	3. The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage.		Periodically	
	• The sand bed region drains will be monitored daily during refueling outages. If leakage is detected, procedures will be in place to determine the source of leakage and investigate and address the impact of leakage on the drywell shell, including verification of the condition of the drywell shell coating and moisture barrier (seal) in the sand bed region and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage.		Daily during refueling outages	
	• The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as		Quarterly during non-outage periods	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage: • Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region • UTs of the upper drywell region consistent with the existing program • UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred • UT results will be evaluated per the existing program Any degraded coating or moisture barrier will be repaired.			
	4. Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior *surface of the* Drywell *shell in* the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of		Prior to the period of extended operation **(completed during 2006 refueling outage); then every other refueling outage thereafter**	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage. **Note: The scope and frequency for the inspections described in commitment 4 (above) has been changed to all 10 bays every other refueling outage, in accordance with commitment 21 of the IWE Inspection Program.**			
	5. A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations, these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas. **Note: Commitment 5 (above) is supplemented by**		Prior to the period of extended operation **(completed during 2006 refueling outage)**	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	commitments 16 and 20 of the IWE Inspection Program.			
	6. The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Program. The scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.		Every other refueling outage prior to **(completed during 2006 refueling outage)** and during the period of extended operation	
	7. AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured.		Every other refueling outage prior to **(completed during 2006 refueling outage)** and during the period of extended operation	
	8. The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.			
	9. During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned		Prior to the period of extended operation **(completed during 2006 refueling**	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA). **Note: Commitment 9 (above) is supplemented by commitments 14 and 21 of the IWE Inspection Program.**		**outage); then every other refueling outage thereafter**	
	10. AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell. These measurements will be taken at four locations using the 6"x6" grid. The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have had corrosion or leakage). These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the		Prior to the period of extended operation and two refueling outages later	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	upper drywell (every other refueling outage).			
	11. AmerGen will conduct UT thickness measurements in the drywell shell "knuckle" area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at four locations using the 6"x6" grid. The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have had corrosion or leakage). These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).		Prior to the period of extended operation and two refueling outages later	
	12. When the sand bed region drywell shell coating inspection is performed **(item** 27, **commitments** 4 **and 21**), the seal at the junction between the sand bed region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program. **Note: The frequency for the inspections described in commitment 12 (above) has been changed to every other refueling outage, in**		**Prior to the period of extended operation (completed during 2006 refueling outage); then every other refueling outage thereafter**	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	***accordance with commitment 21 of the IWE* Inspection Program.**			
	13. The reactor cavity concrete trough drain will be verified to be clear from blockage once per refueling cycle. Any identified issues will be addressed via the corrective action process.		Once per refueling cycle	
	14. UT thickness measurements will be taken from outside the drywell in the sandbed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected. **Note: The frequency for the inspections *described in commitment 14* (above) has been changed to every other refueling outage, in accordance with commitment 21 of the IWE Inspection Program.**		During the 2008 refueling outage **and every other refueling outage thereafter**	
	15. Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sandbed region in two bays per outage, such that inspections will be performed in all 10 bays		**All 10 bays will be inspected during the 2008 refueling outage and every other**	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are identified. **Note: The scope and frequency for the inspections described in commitment 15 (above) have been changed to all 10 bays every other refueling outage, in accordance with commitment 21 of the IWE Inspection Program.**		**refueling outage thereafter.**	
	16. Perform visual inspection of the drywell shell inside the trenches in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas. **Note: Commitment 16 (above) is supplemented by commitment 20 of the IWE Inspection Program.**		During the 2008 refueling outage and subsequent **refueling** outages until trenches are restored to original configuration	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	17. Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor/curb, installed inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation. **18. AmerGen will perform a 3-D finite element structural analysis of the primary containment drywell shell using modern methods and current drywell shell thickness data to better quantify the margin that exists above the Code required minimum for buckling. The analysis will include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect Code margins. If the analysis determines that the drywell shell does not meet required thickness values, the NRC will be notified in accordance with 10 CFR 50 requirements.** **19. AmerGen will perform an engineering study to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage.** **20. AmerGen is committed to perform visual and UT inspections of the drywell shell in the inspection trenches in drywell bays 5 and 17 during the**		In accordance with ASME Section XI, Subsection IWE **Prior to the period of extended operation** **Prior to the period of extended operation** **Every refueling outage until trenches are restored**	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	Oyster Creek 2008 refueling outage (see commitment 16 of AmerGen's IWE Program (item 27), made in its letter 2130-06-20426). AmerGen will extend this commitment and also perform these inspections during the 2010 refueling outage. In addition, AmerGen will monitor the two trenches for the presence of water during refueling outages. Visual and UT inspections of the shell within the trenches will continue to be performed until no water is identified in the trenches for two consecutive refueling outages, at which time the trenches will be restored to their original design configuration (e.g., refilled with concrete) to minimize the risk of future corrosion.			
	21. Perform the full scope of drywell sand bed region inspections prior to the period of extended operation and then every other refueling outage thereafter. The full scope is defined as: • UT measurements from inside the drywell (commitment 1) • Visual inspections of the drywell external shell epoxy coating in all 10 bays (commitment 4) • Inspection of the seal at the junction between the sand bed region concrete and the embedded drywell shell (commitment		During the 2008 refueling outage and every other refueling outage thereafter. If the analysis being performed under commitment 18 above establishes increased margin, or if ongoing inspections continue to demonstrate that drywell shell	

ITEM NUMBER	COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	12) • UT measurements at the external locally thinned areas inspected in 2006 (commitments 9 and 14)		corrosion has been sufficiently arrested, the period between inspections may be increased to minimize personnel radiation exposure.	

AFFIDAVIT OF JON R. CAVALLO

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of: AmerGen Energy Company, LLC (License Renewal for Oyster Creek Nuclear Generating Station)	Docket No. 50-219

AFFIDAVIT OF JON R. CAVALLO

City of Portsmouth)
)
State of New Hampshire)

Jon R. Cavallo, being duly sworn, states as follows:

INTRODUCTION

1. This Affidavit is submitted to support AmerGen Energy Company, LLC's Motion for Summary Disposition on the contention filed by environmental and citizen groups ("Citizens") opposed to the renewal of the Oyster Creek Nuclear Generating Station operating license, and admitted by the Licensing Board on October 10, 2006. Citizens' contention as admitted by the Licensing Board is: "AmerGen's scheduled [ultrasonic testing ("UT")] monitoring frequency in the sand bed region is insufficient to maintain an adequate safety margin." The purpose of my Affidavit is provide

information regarding the multi-layer epoxy coating used on the exterior of the Oyster Creek drywell shell in the sand bed region, in order to address Citizens' contention.

2. It is my expert opinion that Citizens' allegations have no technical merit because they are based on a misunderstanding of the nature of the epoxy coating, and of the inspections performed on that coating.

EDUCATION AND EXPERIENCE

3. I am Vice President of Corrosion Control Consultants & Labs, Inc., and in this capacity I provide corrosion mitigation professional engineering services in surface preparation, protective coatings and linings. I have held this position since 1998. I am also Vice-Chairman of Sponge-Jet, Inc., located in Portsmouth, New Hampshire, a company I helped found which designs and manufactures state-of-the-art surface preparation and decontamination systems.

4. I served as Editor of Electric Power Research Institute (EPRI) Report 1003120 (formerly TR-109937), Revision 1, "Guideline on Nuclear Safety-Related Coatings." I also teach and assisted developing the EPRI protective coatings course. I am also the Principal Investigator of EPRI Report 1009750, "Analysis of Pressurized Water Reactor Unqualified Original Equipment Manufacturer Coatings," (Final Report, March 2005).

5. I have worked on coatings and corrosion control at nuclear power facilities for over 35 years. Specifically:

   - From 1971 to 1983, I was employed by Stone & Webster Engineering Corporation in both the Boston and Denver offices. During this period, I specified coating systems for a number of new nuclear generating facilities as well as performed coating system failure analysis and attendant repair plans for operating nuclear generating facilities.

- After leaving Stone & Webster, I worked with Metalweld, Inc. until 1986 as its Northeastern United States regional manager. I was the project manager for all of the protective coatings work for the Seabrook Nuclear Plant.
- From 1986 to 1991, I was a Senior Associate in the consulting engineering firm of S.G. Pinney & Associates, Inc. During my employment with the firm, I performed protective coating and lining work at a number of nuclear generating facilities. I was the Professional Engineer assigned to all underwater protective lining work conducted by the firm.
- From 1991 to 1998, I was an independent professional engineer performing corrosion engineering consulting services.
- From 1998 to the present, I have worked in my current capacity as Vice President of Corrosion Control Consultants & Labs, Inc.

6. I received my B.S. degree in Engineering Technology, *cum laude*, from Northeastern University in Boston, Massachusetts, in 1979. I have completed a variety of engineering and engineering management study programs, including U.S. Naval Nuclear Power Training, the University of Colorado (engineering project management), and NACE International (corrosion prevention in oil and gas production). I am a Registered Professional Engineer in six states, President of the Maine Society of Professional Engineers, and an SSPC-Society for Protective Coatings certified Protective Coating Specialist.

7. I am active on a number of national technical societies including SSPC, NACE and ASTM. I have served as Chairman of the Northern New England Chapter of SSPC from 1991 to 1998, Chairman of the New England Chapter of SSPC from 2000 to the present, and was a member of the SSPC National Strategic Planning Committee. I was elected Chairman of ASTM Committee D-33 (Protective Coating and Lining Work for Power Generation Facilities) for the period 2004 through 2008. I have also served as Chairman of the Industry Coating Phenomena Identification and Ranking Table (PIRT) Panel reviewing the work of Savannah River Technical Center on the USNRC Containment Coatings Research Project (Generic Safety Issue -191).
8. Based on my review of the relevant historical documentation, I am familiar with the historical corrosion of the OCNGS drywell shell, and the actions taken to control corrosion.
9. I have also reviewed the relevant portions of the OCNGS License Renewal Application ("LRA") submitted to the NRC on July 22, 2005, and the LRA supplement submitted to the NRC on December 3, 2006.
10. Finally, I testified before the Advisory Committee on Reactor Safeguards (ACRS) license renewal subcommittee on January 18, 2007, on the topic of the Oyster Creek drywell shell epoxy coating.

OPINIONS OF JON R. CAVALLO

11. Citizens have asserted that under corrosive conditions, long-term corrosion rates of more than 0.017 inches per year have been observed in the sand bed region of the Oyster Creek drywell shell. This assertion is based on public documents estimating

long term corrosion rates in the period before the application of the epoxy coating to the drywell shell.

12. The historic corrosion occurred because, among other things, the drywell shell in the sand bed region was not coated. The exterior shell is now protected by a three-layer (pre-prime and two coats) epoxy coating system. This coating system was designed for submerged applications, such as tank bottoms, so even if water was always present in the sand bed region, it would have no effect on the coated steel shell. This coating was applied in the following manner:

- Prior to application, Oyster Creek personnel created a mock-up of the sand bed region. Using the same mechanics, and with the same restricted access, personnel prepared the surface and applied to the coating to this mock-up. Through this process, Oyster Creek personnel qualified the surface preparation, coating application, and inspection techniques for use on the drywell shell.
- Following surface preparation of the drywell shell by SSPC-SP 2 hand tool cleaning that removed loose rust, loose mill scale, and loose coating, the pre-prime was applied.
- The pre-prime is a red epoxy coating that soaks and penetrates into the semi-irregular shape of the substrate metal.
- Then two coats of the whitish-gray Devran-184 epoxy were applied with a brush and roller.
- Finally, a Devmat 124S caulking was used to seal the interface between the concrete floor and the steel substrate.

13. Citizens speculate that there might be tiny holes in the epoxy coating - "pinholes" or "holidays" - which would allow water to get behind the coating, causing corrosion of the underlying drywell shell. Dr. Hausler has suggested that such holidays would be so small that they could not be detected with the naked eye during a visual inspection. By definition, a pinhole or holiday is a very localized defect in the coating that occurs during the application and cure of the coating. Thus, these localized defects could only be caused by a defect in the original application of the coating, and cannot be caused by degradation over time.

14. As would be expected, the possibility of a pinhole or holiday decreases with each layer of coating that is applied. As I noted, the epoxy protecting the exterior of the drywell shell is comprised of a three layer (a pre-prime and two coats) coating system.

15. AmerGen's protective coating monitoring program includes VT-1 visual inspections of the epoxy coating by qualified inspectors in accordance with NUREG-1801 and ASME Section 11, Subsection IWE. Under the VT-1 method, trained and qualified individuals inspect surfaces such as the drywell shell for evidence of flaking, blistering, peeling, discoloration, and other signs of degradation. The VT-1 technique is a proven method, used throughout the industry, on both boiling water reactors and pressurized water reactors. If a corrosion rate of 0.017" per year had occurred between 1992 and 2006, then it would have been readily detected by the VT-1 inspections performed during the 2006 refueling outage. Future corrosion would also be detectable in a VT-1 inspection.

16. This is because as carbon steel corrodes, the reaction between oxygen and the iron in the steel results in an iron oxide byproduct. The epoxy coating would not allow the corrosion byproducts to migrate from the site of the corrosion, so these byproducts would either accumulate as a blister at the corrosion site, or they would seep out through the postulated pinhole or holiday in the coating onto the otherwise whitish-gray epoxy coating. In either case, the corrosion byproducts would be clearly visible in a VT-1 inspection.

17. It is well accepted corrosion science that corrosion byproduct occupies a volume seven to ten times greater than the underlying corroding steel. For example, if 0.017" of steel corrodes in a year under an epoxy coating, then between 0.119" and 0.170" of byproduct would result. Four years of corrosion at that rate—the interval that AmerGen will perform UT in the sand bed region—would result in between 0.476" and 0.680" of corrosion byproduct. Thus, the amount of corrosion that Citizens postulate would, in a four-year period, generate a blister under the epoxy coating of around ½-inch thickness. Such a blister would be clearly visible to an inspector qualified to perform VT-1 inspections.

18. Therefore, a corrosion rate of 0.017" occurring in a pinhole since 1996 (the last time that strippable coating was not used during a refueling outage), would result in a 1.2" to 1.7" blister in the epoxy coating. Even if significant corrosion could occur behind a pinhole or holiday in the epoxy coating, corrosion at a rate of 0.017" per year would be visible through the VT-1 inspections performed every four years.

19. In fact, Citizens' argument that such local defects have existed since 1992 is inconsistent with their argument that the air in the sand bed region is moist and

capable of corrosion. If a moist environment and pinholes coexisted for the past 14 years (1992 to 2006), then the resulting corrosion would be easily visible during the VT-1 inspections.

20. The VT-1 inspections would also detect the corrosion products caused by much lower corrosion rates. Even a corrosion rate of 0.002 inches per year would yield corrosion products that would cause a blister of between 0.056" and 0.080" in the four year interval between inspections. Such a blister would also be visible in a VT-1 inspection performed by a qualified inspector.
21. The VT-1 Inspection is designed to be used on any type of steel or concrete surface, including textured concrete and irregular surfaces such as welds. Therefore, the techniques used in this inspection would be adequate to use on surfaces such as the Oyster Creek drywell shell.
22. Also, the eight to ten year rated lifetime discussed in Citizens' Exhibit 6 to their original contention (this exhibit is a letter submitted to the NRC in 1995 by the previous owner of Oyster Creek Nuclear Generating Station) is simply incorrect. The multilayer epoxy coating is designed to withstand a submerged environment and to last for the life of the plant, including the extended period of operation, provided that proper VT-1 inspections are conducted and necessary corrective maintenance is performed to address any discrepancies found. This type of coating is commonly used throughout the nuclear industry, and there is no such limitation in life span.

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Jon R. Cavallo
235 Heritage Avenue, Suite 2
Portsmouth, NH 03801

Subscribed and sworn before me this 26th day of March, 2007.

Joyce L. Goodwin
Notary Public

My Commission Expires: JOYCE L. GOODWIN, Notary Public
My Commission Expires January 15, 2008

AFFIDAVIT OF BARRY GORDON

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of: AmerGen Energy Company, LLC (License Renewal for Oyster Creek Nuclear Generating Station)	)	Docket No. 50-219

AFFIDAVIT OF BARRY GORDON

City of San Jose)
)
State of California)

Barry Gordon, being duly sworn, states as follows:

INTRODUCTION

1. This Affidavit is submitted to support AmerGen Energy Company, LLC's Motion for Summary Disposition on the contention filed by environmental and citizen groups ("Citizens") opposed to the renewal of the Oyster Creek Nuclear Generating Station ("OCNGS") operating license, and admitted by the Licensing Board on October 10, 2006. That contention challenges the frequency of AmerGen's UT measurements of the drywell shell in the sand bed region. In part of their contention, Citizens speculate that significant corrosion of the exterior of the OCNGS drywell shell in the sand bed region could occur through tiny defects (called "pinholes" or holidays") in

the three-layer epoxy coating system: "corrosion may occur under the epoxy coating in the absence of visible deterioration due to non-visable holidays, or pinholes."

2. As I discuss below, it is my expert opinion that these allegations have no technical merit because: (a) significant corrosion is not possible with an epoxy-coated drywell shell; and (b) even if such a corrosion rate was possible, AmerGen's committed frequency of UT measurements is more than adequate to detect such corrosion (even under unrealistic assumptions), before the ASME Code-specified margins are exceeded. Accordingly, Citizens' argument is not only factually irrelevant but simply immaterial to the integrity of the drywell shell during the proposed period of extended operation.

EDUCATION AND EXPERIENCE

3. For the past 38 years, I have been an engineer focusing on corrosion and material issues in light-water reactors, with special emphasis on stress corrosion cracking (SCC). I have addressed numerous materials and corrosion issues in the nuclear industry in a wide range of contexts including reactor internals, piping, fuel hardware, water chemistry transient and core flow issues, weld overlays and repairs, crack growth rate modeling, alloy selection, failure analysis, license renewal, NRC inspection relief, dry fuel storage, and decontamination.

4. I received my B.S. and M.S. degrees in Metallurgy and Material Science from Carnegie Mellon University in 1969 and 1971, respectively. Since then, I have completed additional courses from M.I.T., the University of Pittsburgh and the National Association of Corrosion Engineers (NACE) in Corrosion Science.

5. I am a Registered Professional Engineer in Corrosion Engineering in the State of California (#208), a Registered Corrosion Specialist with NACE International (#1986) and a Member of the International Cooperative Group on Environmentally Assisted Cracking (ICG-EAC).
6. I was certified as an Instructor for the International Atomic Energy Agency (IAEA) on February 2001 and am an Adjunct Professor at the Colorado School of Mines, in Golden, Colorado where I currently supervise one Ph.D candidate. I teach the following course: "Corrosion and Corrosion Control in LWRs" for Structural Integrity Associates, Inc. and have taught "Corrosion and Corrosion Control in BWRs" for GE Nuclear Energy (GENE). I have held instructor credentials for Engineering in California Community Colleges since 1986.
7. From 1969 to 1975, I was employed as a materials engineer by Westinghouse Electric at the Bettis Atomic Power Laboratory, located in West Mifflin, Pennsylvania.
8. From 1975 to 1998, I was employed by GE Nuclear Energy, located in San José, California. While at GE Nuclear Energy, I was a technical expert in corrosion engineering, a project manager in corrosion technology, and a program manager in stress corrosion cracking.
9. Since 1998, I have been employed by Structural Integrity Associates, Inc., also located in San José, California, as an Associate.
10. I am familiar with the historical corrosion of the OCNGS drywell shell because I started working on that issue in 1986 as the OCNGS drywell project manager when I was employed by GENE.

11. More recently, I prepared an evaluation report on the corrosion of steel embedded in concrete on the exterior of the drywell (June 5, 2006) and on effects of water on corrosion propensities of concrete embedded steel identified in the interior of the drywell (November 3, 2006). I also testified before the Advisory Committee on Reactor Safeguards (ACRS) on both subjects on January 18, 2007.

OPINIONS OF BARRY GORDON

12. In his June 23, 2006, memorandum, Dr. Rudolf Hausler suggests that a future corrosion rate of 0.017" per year is possible for the external surface of the drywell shell in the sand bed region at OCNGS. He correctly asserts that this corrosion rate was observed by the former owner of the OCNGS in certain areas of the sand bed region prior to 1992 (after which the external surface of the drywell shell was protected from further corrosion by a sand bed removal and the installation of a multi-layer epoxy coating system). As I demonstrate below, however, this corrosion rate is not possible with an epoxy-coated drywell shell. Moreover, even if this or a significantly higher corrosion rate was possible, AmerGen's committed frequency of UT measurements is more than adequate to detect such corrosion before the ASME Code-specified margins are exceeded.

13. Part of the reason why the corrosion rate was historically as high as 0.017" per year in certain bays of the drywell shell sand bed region is because there was a medium (*i.e.*, sand) to physically hold water against the drywell shell. Specifically, the sand bed region got its name from the sand that was placed there as part of the original design. Once water entered this area, the sand physically held the water against the shell, ensuring a constant source of water to facilitate corrosion of the metal drywell shell.

This sand, however, was removed as part of the corrective actions completed in 1992 to prevent additional corrosion in the sand bed region. So there is no water-retaining media to facilitate future corrosion.

14. Of course, such a corrosion rate of 0.017" per year is unrealistic because the drywell shell is protected from further corrosion by a multi-layer epoxy coating system. AmerGen has demonstrated that corrosion of the external surface of the drywell shell has been arrested, and no additional corrosion is possible unless there is a defect in the coating and water is able to come into contact with the metal drywell shell through that defect. Accordingly, it is my opinion that no corrosion is possible beneath an intact epoxy coating system, such as the one applied on the exterior of the OCNGS. This is because corrosion of a kind significant enough to affect the integrity of the drywell shell requires the presence of water and oxygen, and there is no water or oxygen adjacent to the metal surface of the drywell shell to initiate, let alone sustain, the corrosion process.

15. Dr. Hausler, however, has speculated that there could be tiny defects in the coating, referred to as "pinholes" or "holidays." He essentially argues that water could get to the metal surface of the underlying drywell shell through these hypothetical, tiny defects. It is my opinion that even if there were such defects, they would not allow sufficient oxygenated water to reach the underlying drywell shell for corrosion to exceed ASME Code-specified margins before AmerGen would detect it through its committed inspections (*i.e.*, every four years). Accordingly, this argument is simply not relevant to the long-term integrity of the drywell shell. The support for my opinion is presented in the next paragraphs.

16. We know that the maximum measured historical corrosion rate was not 0.017" per year, but was more than twice that at 0.039" per year (in location Bay 13A).[1] So we know that with the presence of water, wetted sand holding that water adjacent to the uncoated shell, blocked drains preventing that water from being drained out of the sand bed region, and the temperature specific to the exterior of the drywell shell in the sand bed region during operations, that loss of metal at a rate of 0.039" per year is possible.

17. To show how absurd Citizens' argument is—that corrosion significant enough to affect the integrity of the drywell shell could occur through a pinhole or holiday in the epoxy coating—I have made the following assumptions in my calculation, some of which are unrealistic and overly conservative:

    - AmerGen performs the visual and UT inspections of the sand bed region in 2008 that it has already committed to;
    - AmerGen does not perform inspections of the sand bed region in 2010, also consistent with its commitments (inspections are to be performed every four years after 2008);
    - The drywell shell is exposed to water during the 2010 scheduled refueling outage. The source of the water is minor leakage from the refueling cavity, which only contains water during refueling outages, so the shell could not get wet prior to a refueling outage;

1 Citizens' Petition states that a "reasonable estimate of the worst case potential corrosion rate that may occur could be obtained by analyzing the pre-1992 data [*i.e.*, before the sand was removed from the sand bed region].... Observed corrosion rates to 1990 ranged up to 0.035 inches per year and were very uncertain." While it is my understanding that AmerGen is not required to perform "worst case" analyses, the corrosion rates that occurred prior to removal of the sand from the sand bed region simply are not representative of the potential corrosion rates after removal of the sand. As I demonstrate in this Affidavit, even this order of magnitude corrosion does not challenge the integrity of the drywell shell.

- This water is not detected. This is conservative because AmerGen's commitments include monitoring the refueling cavity liner drain during outages, as well as the five sand bed region drains both quarterly and daily during outages;
- The water enters Dr. Hausler's hypothetical pinhole or holiday on the first day of the 2010 refueling outage. This is conservative because the refueling cavity is not even flooded on the first day of the outage;
- The pinhole or holiday is located within the region that has the least remaining margin (*i.e.*, Bay 13). This is conservative because it is statistically unlikely that the thinnest area of the shell also has the defect in the coating;
- Corrosion at the maximum historical rate of 0.039" per year instantly begins as water enters the pinhole or holiday;
- Oxygen's contact with the metal surface is not mitigated by the presence of corrosion products. This is conservative because corrosion tends to be self-limiting when corrosion films are produced on the metal surface and corrosion byproducts (*i.e.*, rust) create a diffusion barrier that reduces the amount of subsequent corrosion of the shell;
- The refueling outage takes four weeks to complete, and the cavity is filled with water during the entire refueling outage;
- The water stays in the pinhole during the entire four-week outage; and
- The water in the pinhole or holiday does not evaporate until a year after the refueling outage is over, and the 0.039" per year corrosion rate continues for the entire year after the outage, for a total of 56 weeks of new corrosion. This

is extremely conservative because the temperature in the sand bed region of the drywell is about 130°F during operations, which would result in the evaporation of the small amount of water in the pinhole or holiday in significantly less time. For example, at 130°F, a drying out rate of about 0.3 pounds per hour, per square foot, is reasonable for a sand bed region with no sand.[2] This would result in evaporation of water in the pinhole or holiday in less than one day. There are many factors involved in the calculation of water evaporation rates. One of the most important factors is the air or wind velocity across the water surface. I derived the 0.3 pounds per hour, per square foot value from the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) equation for evaporation from ponds or pools: $W = [A + (B)(V)](Pw - Pa)/Hv$ (where: W = water evaporation rate, (lb/hr) per sq.ft. of the water's surface area; A = a constant = 95; B = a constant = 37.4; V = air velocity over the pond surface, miles/hr (which I assumed was zero); Pw = vapor pressure of water at the water temperature, inches of Hg; Pa = vapor pressure of water at the air dewpoint temperature, inches of Hg; and Hv = heat of vaporization of water at the pond water temperature, Btu/lb).

18. In summary, therefore, I have assumed that the drywell shell behind the pinhole or holiday will experience the maximum historical corrosion rate of 0.039" per year, for 56 weeks. This results in a total loss of metal of about 0.042", which is well within: (a) the margin of 0.064" remaining in Bay 19 (thickness of 0.800"), when measured

[2] This is around 2.4 ounces per hour, per square foot.

against the general average thickness criterion of 0.736"; and (b) the margin of 0.128" remaining in Bay 13A, when measured against the very local area average thickness of 0.490".

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Barry Gordon
Structural Integrity Associates, Inc.
3315 Almaden Expressway, Suite 24
San Jose, CA 95118-1557

Subscribed and sworn before me this 26 day of March 2007.

PAULA RODGERS
Commission # 1540492
Notary Public - California
Santa Clara County
My Comm. Expires Jan 1, 2009

Notary Public

My Commission Expires: Jan. 1, 2009

AFFIDAVIT OF PETER TAMBURRO

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	
AmerGen Energy Company, LLC	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AFFIDAVIT OF PETER TAMBURRO

Lacey Township)
)
State of New Jersey)

Peter Tamburro, being duly sworn, states as follows:

INTRODUCTION

1. This Affidavit is submitted to support AmerGen Energy Company, LLC's Motion for Summary Disposition on the contention filed by environmental and citizen groups ("Citizens") opposed to the renewal of the Oyster Creek Nuclear Generating Station ("OCNGS") operating license, and admitted by the Licensing Board on October 10, 2006.

2. The contention, as admitted by the Licensing Board states: "AmerGen's scheduled [ultrasonic testing ("UT")] monitoring frequency in the sand bed region is insufficient to maintain an adequate safety margin." The purpose of my

Affidavit is to address Citizens' allegations regarding the frequency of AmerGen's UT measurements.

3. It is my expert opinion that these allegations have no technical merit because they are based on a misinterpretation of the governing thickness criteria, calculation errors, and speculation about future conditions.

4. It is also my opinion that the frequency of UT of the sand bed region of the drywell shell reflected in AmerGen's existing commitments to the NRC is sufficient to provide reasonable assurance that the applicable thickness acceptance criteria will be met, that an adequate safety margin will be maintained during the period of extended operation under a renewed license, and that the drywell will continue to serve its intended functions.

EDUCATION AND EXPERIENCE

5. I received my B.S. degree in Chemical Engineering from Clarkson University, Potsdam, New York, in 1980. I received my M.S. in Computer Science from Fairleigh Dickinson University, Teaneck, New Jersey, in 1986. I first registered as a Professional Engineer in the State of New Jersey around 1986.

6. I currently am employed as Senior Mechanical Engineer in the Engineering Department at the Oyster Creek Nuclear Generation Station. My current responsibilities include:

   - Implementing the above- and below-ground piping monitoring program to ensure piping is capable of performing its intended function. This includes maintaining operating history, risk-ranking plant piping systems, establishing inspection scope and criteria, analyzing inspection results, sponsoring modification and replacement based on inspection results, and overseeing the design and installation of new piping systems. My responsibilities also include the temporary and permanent repair of piping leaks at OCNGS.

- Implementing the OCNGS Drywell Vessel Monitoring Program. This program ensures that the Drywell Vessel (a.k.a. "shell") is inspected consistent with current regulatory commitments. This includes setting scope for future inspections and analysis of inspection results.

7. My past responsibilities included designing and implementing modifications at OCNGS. This included new below- and above-ground piping from 1992 to 2006, and engineering oversight and implementation of all Security Upgrades at the plant from 1998 to 2006.

8. I am very familiar with the historical corrosion of the OCNGS drywell shell. My involvement began in 1988 when I took over the responsibility for "10 CFR 50.59" Evaluation of the issue. This included comparing the design requirements of the shell with the inspection results. This also included setting the outage-related inspection scope, and reporting to the NRC throughout that time period on the results of those inspections.

9. Since 1996, I have been responsible for ensuring upper drywell inspections are performed every other outage. I have also analyzed those inspection results.

10. With respect to license renewal, I have provided historical perspective on drywell corrosion, corrective actions, and inspection. I reviewed and commented on the drywell-related portions of the OCNGS License Renewal Application ("LRA") submitted to the NRC on July 22, 2005, and the LRA supplement submitted to the NRC on December 3, 2006.

11. I supported the NRC license renewal audits and inspections in 2006 as the lead engineer responsible for drywell–related inspections. I supported the response to the NRC Staff's requests for additional information.

12. I assisted in developing the inspection scope for the October 2006 refueling outage, and I analyzed all inspection results.

13. I also participated, as a site engineer knowledgeable about drywell issues, in meetings with the Advisory Committee on Reactor Safeguards (ACRS) on October 3, 2006, January 18, 2007 and February 1, 2007.

OPINIONS OF PETER TAMBURRO

I. Citizens' Allegation of 0.026" Remaining Margin Is Technically Unsupportable

14. I understand that Citizens have asserted that the drywell shell in the sand bed region is 0.026" or less away from exceeding the acceptance criteria for buckling developed by GE Nuclear in the early 1990s. As I explain below, this assertion is based on a misinterpretation of the 0.536" local area average thickness criterion.

15. By way of background, the acceptance criteria for the drywell shell in the Oyster Creek sand bed region are the minimum thicknesses required for the drywell to perform its intended functions. GE Nuclear analyses established these criteria in 1991 and 1992, and they form part of the Oyster Creek current licensing basis.

16. Before the sand was removed from the sand bed region, GE Nuclear performed an engineering analysis of the drywell shell to determine whether historical corrosion prevented the drywell from performing its intended functions. GE Nuclear conducted this analysis in 1991, based on ASME Code requirements, to establish the minimum

required general thickness, with the sand removed, for both pressure and buckling stresses.

17. The results of GE Nuclear's analysis show that the minimum required thickness in the sand bed region is controlled by buckling. By "controlled", I mean that for the analyses performed to model design conditions that might lead to structural degradation, the analysis for buckling showed the least margin. Moreover, a general thickness of 0.736" will satisfy ASME Code requirements with a safety factor of 2.0 against buckling for the controlling operating load combination (*i.e.*, during refueling), and 1.67 safety factor for the accident flooding load combination (*i.e.*, during operations).

18. At that time, a "very local" area thickness of 0.490", not to exceed 2.5 inches in diameter, was also identified. This "very local" thickness criterion is relevant to Citizens' argument about pinholes or holidays, which I discuss in paragraphs 42 and 43, below. However, it is not pertinent to Citizens' argument about 0.026" remaining margin, as I discuss below.

19. In 1992, GE Nuclear performed a series of sensitivity analyses on the original 0.736" criterion. These analyses sequentially evaluated locally-thinned areas using one square foot areas of 0.636" and 0.536", each with a transition to the surrounding shell at a uniform thickness of 0.736". Since Dr. Hausler only references the 0.536" analysis, I will discuss only that analysis.

20. Thus, there are two criteria relevant to Citizens' argument. The first criterion is a *general* average thickness of 0.736". An area of average thickness less than 0.736" remains adequate if it meets the second criterion, which is the 0.536" *local area* average thickness, and other factors such as location, configuration, etc. This local

area criterion includes a one-foot *transition area* to 0.736" on all four sides of the 0.536" area, such that the total allowable contiguous area with thickness below 0.736 is *nine square feet*. This is clearly shown on Figure 1 which I created, and which is based on the GE Nuclear report that was attached to the AmerGen submittal to the ACRS on December 8, 2006, as Reference 22.

21. Dr. Hausler interprets the *local area* criterion as being exceeded if the area thinner than 0.736" is greater than one square foot. He states in his June 23, 2006, memorandum that an area "approximately 1.6 square feet" thinner than 0.736" would be "well beyond the current acceptance criterion." This statement can only be based on a misunderstanding of the local area thickness criterion, which allows for nine square feet.

22. Dr. Hausler's misunderstanding seems to stem from his belief that the local area acceptance criterion is configured with an abrupt step-change (like a cliff) on all sides of the one square foot area that averages 0.536", such that the thickness increases to 0.736" with no transition. See Figure 2.

23. Thus, even if an area of approximately 1.6 square feet thinner than 0.736" existed, the local area acceptance criterion still would not be exceeded because that criterion allows for an area thinner than 0.736" of nine square feet.

24. The actual bounding general average thickness in the sand bed region is 0.800" located in Bay 19, which leaves a margin of 0.064" when compared to the 0.736" general area thickness criterion, not 0.026". All the other bays have greater margin, ranging from 0.074" in Bay 17, to 0.439" in Bay 3. The thinnest local measurement identified by Dr. Hausler was 0.618" located in Bay 13. This leaves a margin of 0.082" when compared to the 0.536" local area thickness criterion.

25. Citizens' assertion that the margin above the acceptance criteria is as low as 0.026", therefore, is not supported by the data.

26. The entirety of Dr. Hausler's argument about the 0.026" of metal thickness can be found on page 7 of his June 23, 2006 memorandum. I will now walk through Dr. Hausler's argument and demonstrate that in addition to misinterpreting the local area acceptance criterion as one square foot, his calculations also are wrong. In order to argue that this criterion will be exceeded in the future, he takes a thin point in Bay 13, and makes an assumption that future corrosion will increase the area around this point such that the area will be larger than one square foot. In other words, he speculates that corrosion—which cannot occur while the epoxy coating is intact—will make the thinned area wider.

27. Dr. Hausler bases his conclusion about 0.026" on the UT data collected from single measurement points on the exterior of the drywell shell in the sand bed region in Bay 13 in 1992.

28. In general, the drywell shell in the sand bed region of Bay 13, prior to 1992, experienced a significant amount of corrosion from the presence of wetted sand. In that bay, the corrosion caused the formation of indentations in a pattern visually similar to the surface of a golf ball. In 1992, before the exterior drywell shell was coated with epoxy, UT measurements showed that the thinnest of these indentations averaged approximately 0.800" in thickness.

29. In 1992, Bay 13 had nine, locally-thin areas less than 0.736". By "locally-thin", I mean the area was less than 2.5" in diameter. The thinnest of these locally thin areas is referred to as "point 7" which had the single thinnest reading of 0.618". Around

this point, the evaluation of the data from 1992 found a larger 6" by 6" square area that averaged at least 0.677" thick.

30. On page 7 of his June 23, 2006 memorandum, Dr. Hausler states that the total area less than 0.736" at "point 7", referring to the area which averages 0.677", is 0.3 square feet. Although the 1992 Oyster Creek reports describe this area as a 6" by 6" square area, Dr. Hausler elects to convert this area into a circular area. The corresponding radius of the circular area, which is 0.3 feet square, is 3.7 inches. I have created Figure 2 to show a profile representing these measurements.

31. Dr. Hausler's next statement is an assumption that is not supported by the data. Dr. Hausler states on page 7 of his June 23, 2006 memorandum that "this area is very sensitive to corrosion because in a length of around 5 inches, the thickness changed from around 0.736 inches to 0.800 inches. Assuming the edge of the hole is a straight line, this means that a change of 0.064 inches in depth occurs over about 5 inches in length." Dr. Hausler assumes that the transition from the thinner area less than 0.736" to areas that are 0.800" or thicker is 5" long (radially). As I said, this assumption is not supported by the data. However, if you construct a model of a hypothetical indentation as described in this unsupported assumption using the 5" transition zone and the corresponding inner radius of the 3.7", the total radius of the model is 8.7" or 17.4" in diameter. Figure 2 also shows this configuration.

32. Dr. Hausler continues with his unsupported assumptions. He concludes that "[t]hus, for the radius of the thin area to change by two inches, the depth would have to change by only 0.026"." The statement that the radius would change 2" can only be an assumption because such a change could only occur through corrosion, and corrosion on the exterior of the drywell shell in the sand bed region has been arrested.

Regardless, by expanding the radius of the indentation by 2", the diameter of the indentation would increase by 4", for a total diameter of 21.7" (this is larger than Dr. Haulser's memo which mentions 17.4" diameter). I have created Figure 3 to show the increase of the radius of the hypothetical indentation by 2".

33. Dr. Hausler then mistakenly concludes that if the 2" radius expansion occurred, then "the total area below 0.736 inches would be approximately 1.6 square feet, well beyond the current acceptance criterion." This conclusion is misleading for a number of reasons.

34. First, this conclusion is proved false by Dr. Hausler's own model. The radius of the expanded area less than 0.736" (shown on Figure 4) is 5.7". Simply calculating the area of a 5.7" radius circle results in 0.709 square feet. This value is significantly less than the 1.6 square foot value that Dr. Hausler offers.

35. Second, Dr. Hausler underestimates how much metal needs to corrode to meet his (incorrect) definition of the local area acceptance criterion. The radius of a 1.6 square foot circle is approximately 8.6". As I explain in ¶31 above, Dr. Hausler uses 8.7" for this value rather than 8.6". See Figure 2. In my opinion, by arriving at his conclusion that a 1.6 square feet area is less than 0.736", Dr. Hausler has made another assumption that the entire original 17.4" diameter indentation is less than 0.736". This assumption would require an additional section of material, 0.033" deep to simply disappear (see Figure 5). Assuming this metal disappeared through corrosion, this corrosion would be in addition to the 0.026" of corrosion that Dr. Hausler hypothesizes. I have created Figure 5 to show the material that would need to disappear (see area designated as "Second Assumed Material Loss").

36. Finally, as I state above, Dr. Hausler then misinterprets the local area acceptance criterion by assuming that an area of one square foot that is thinner than 0.736" exceeds that criterion. He is wrong and I have created Figure 6 to show how the additional corrosion that Dr. Hausler postulates would not exceed the local area thickness criterion. In Figure 6, I have reproduced the acceptance criteria profile from Figure 1, and overlaid Dr. Hausler's assumed contour from Figure 5. The new Figure clearly shows that the acceptance criterion is not exceeded.

II. A Future 0.017" Annual Corrosion Rate Is Also Technically Unsupportable

37. Citizens next argue that corrosion rates around 0.017" per year have been observed. Corrosion rates in the range of .017" per year were observed in the sand bed region prior to 1992. Those rates were developed based upon UT data gathered between 1987 and 1992.

38. If Citizens are suggesting that a corrosion rate of 0.017" per year continued to occur after removal of the sand in 1992, or could occur in the future, they are incorrect for numerous reasons.

39. First, such an allegation ignores corrective actions implemented to date. Much has happened to prevent corrosion from continuing in the sand bed region of the drywell shell. The source of water—the flooded reactor cavity liner during refueling outages—has been identified and controlled. No water is expected to reach the sand bed region when strippable coating is applied to the reactor cavity during refueling outages. Even if some water did reach the sand bed region during refueling outages, the sand has been removed so there is no media to physically hold the water against the drywell shell's exterior. And the historic corrosion occurred because the drywell

shell in the sand bed region was *not* coated. The exterior shell is now protected by a three-layer epoxy coating.

40. Second, if a corrosion rate of 0.017" per year had occurred between 1992 and 2006, it would have been readily detected by the VT-1 and UT performed during the 2006 refueling outage. VT-1 inspections are visual inspections performed in accordance with ASME Section XI subsection IWE, by ASME-qualified inspectors. Based on the information contained in the VT-1 inspection reports generated for the coating in all ten external drywell bays during the October 2006 outage, the epoxy coating is in good condition with no defects or deterioration.

41. AmerGen also collected UT measurement data from both the interior and exterior of the drywell shell in the sand bed region during the 2006 refueling outage. Between 1992 and 2006, the alleged rate of corrosion of 0.017" per year would have resulted in a loss of 0.238" of metal from the drywell shell (0.017" x 14 years), which would easily have been detected, as it is well within the expected equipment measurement error of 0.020". Yet the UT data, coupled with the VT-1 inspection results, confirmed that corrosion on the exterior of the drywell shell has been arrested.

42. Third, even if there was a 0.017" per year corrosion rate, Citizens only have argued that it would be localized. Specifically, Dr. Hausler, in his July 2006 memorandum, speculates that there might be tiny holes—"pinholes" or "holidays"—in the epoxy coating which could allow water to contact the exposed shell in the pinhole or holiday, causing very localized corrosion.

43. Such very localized corrosion would not call into question the appropriateness of AmerGen's UT frequency. Pinholes and holidays are analyzed against the "very local" area acceptance criterion of 0.490" which applies to areas not to exceed 2.5 inches in diameter. The thinnest external point measurement identified by Dr. Hausler was 0.618" located in Bay 13. Simple math demonstrates that there is 0.128" of margin available for a pinhole or holiday in this thinned area in Bay 13 (*i.e.*, 0.618"-0.490"), and that it would take over seven years for this margin to disappear with a corrosion rate of 0.017" per year (*i.e.*, 0.128"/0.017"). AmerGen, however, is performing UT measurements and visual inspections of the drywell shell in the sand bed region, from internal and external locations, in 2008 and then every four years.

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Pete Tamburro

Peter Tamburro
Oyster Creek Nuclear Generating Station
Route 9
Forked River, NJ 08731

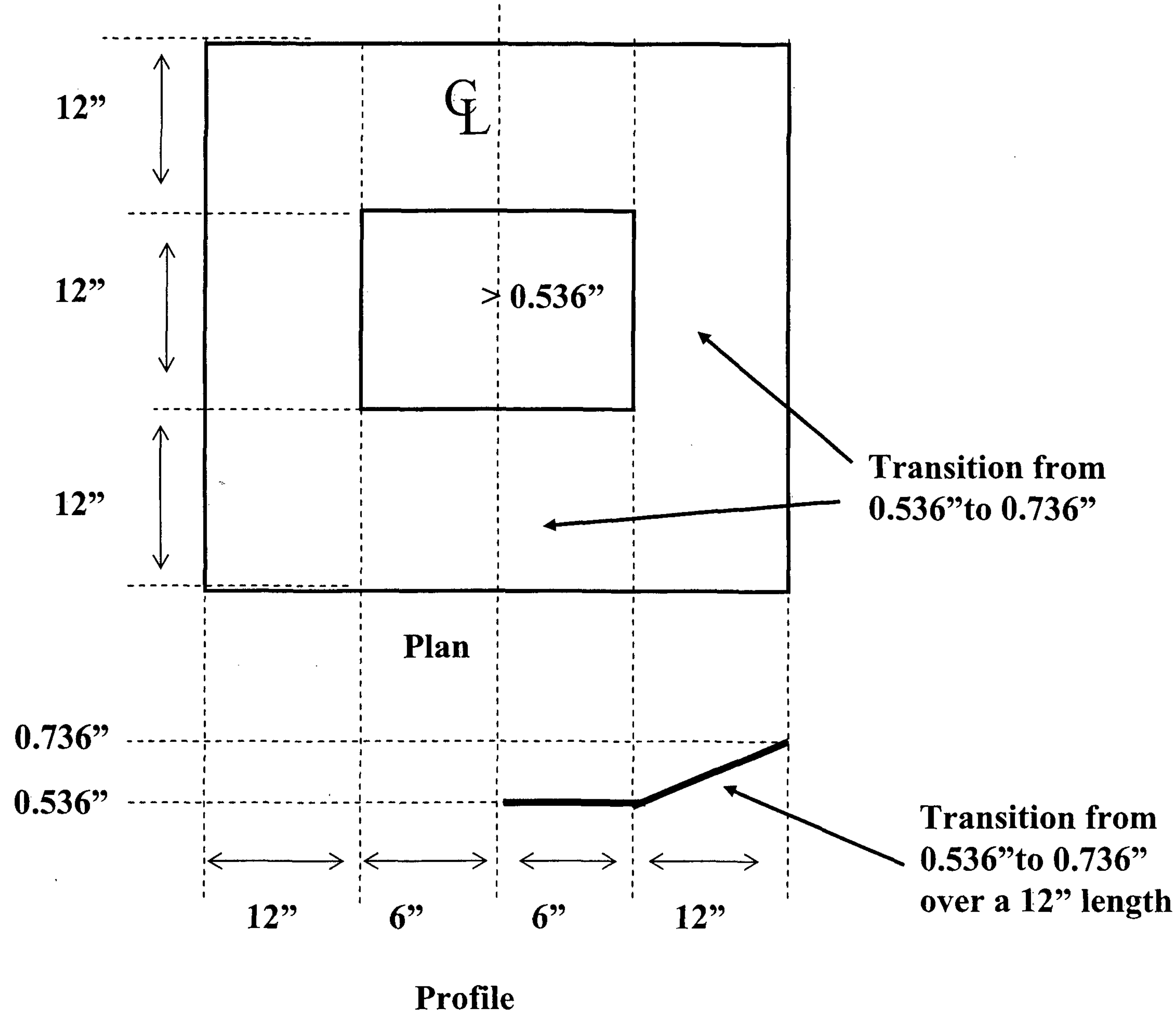
Subscribed and sworn before me this 26 day of March 2007.

Valerie Laudeman

Notary Public

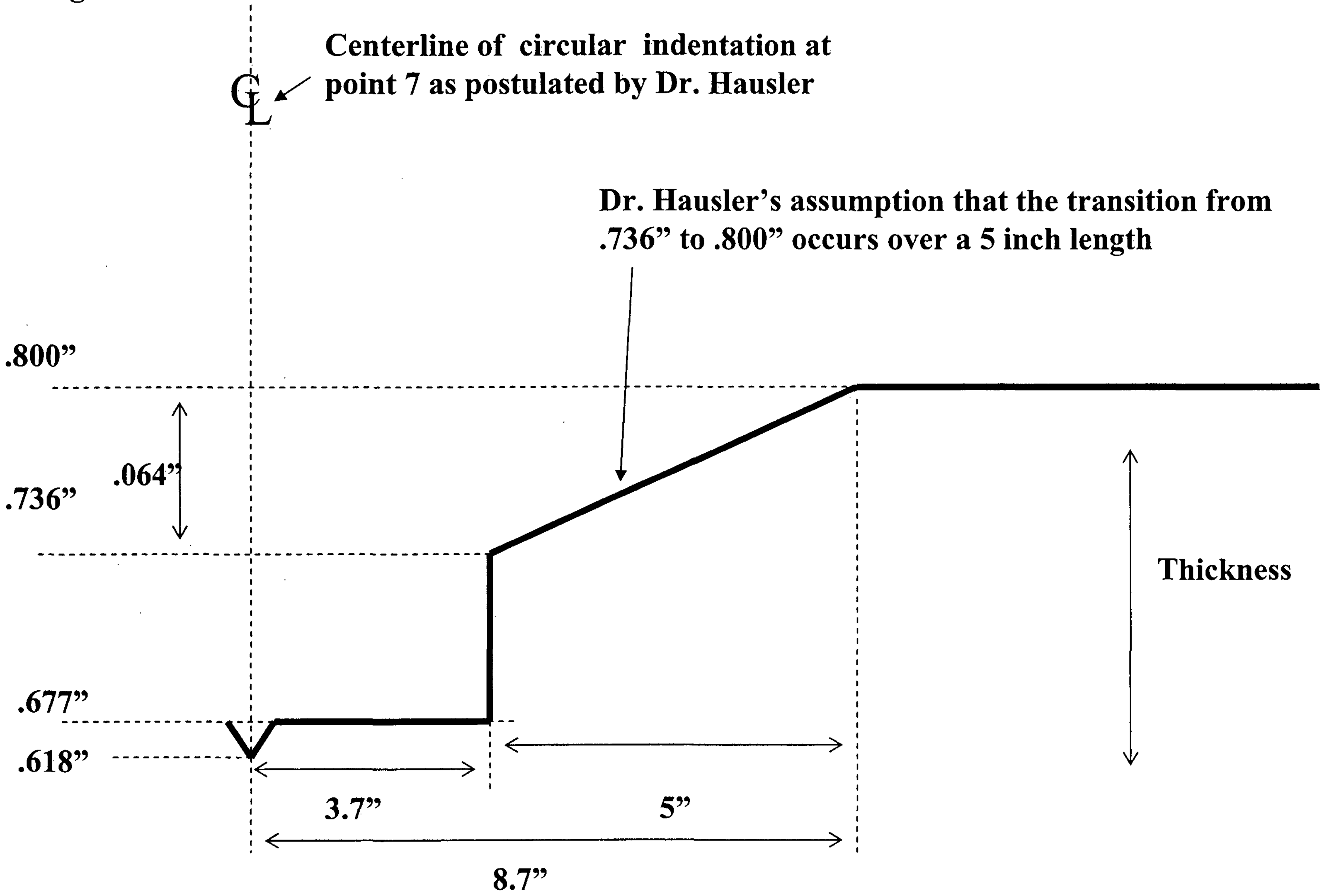
My Commission Expires: VALERIE LAUDEMAN NOTARY PUBLIC OF NEW JERSEY Commission Expires 9/28/2010

Figure 1 **Schematic Demonstrating Local Area Average Acceptance Criterion**



Not to Scale

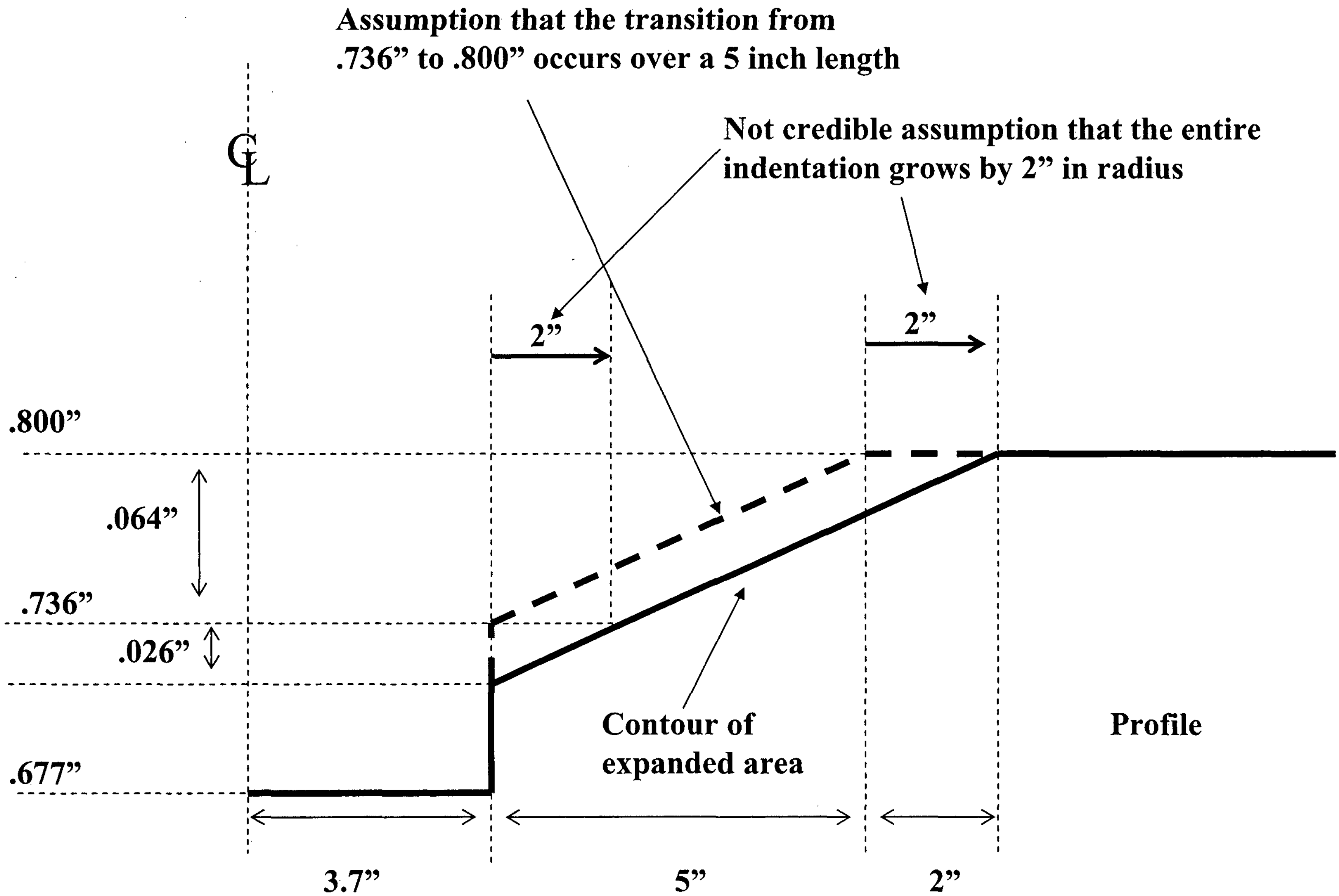
Figure 2



Not to Scale

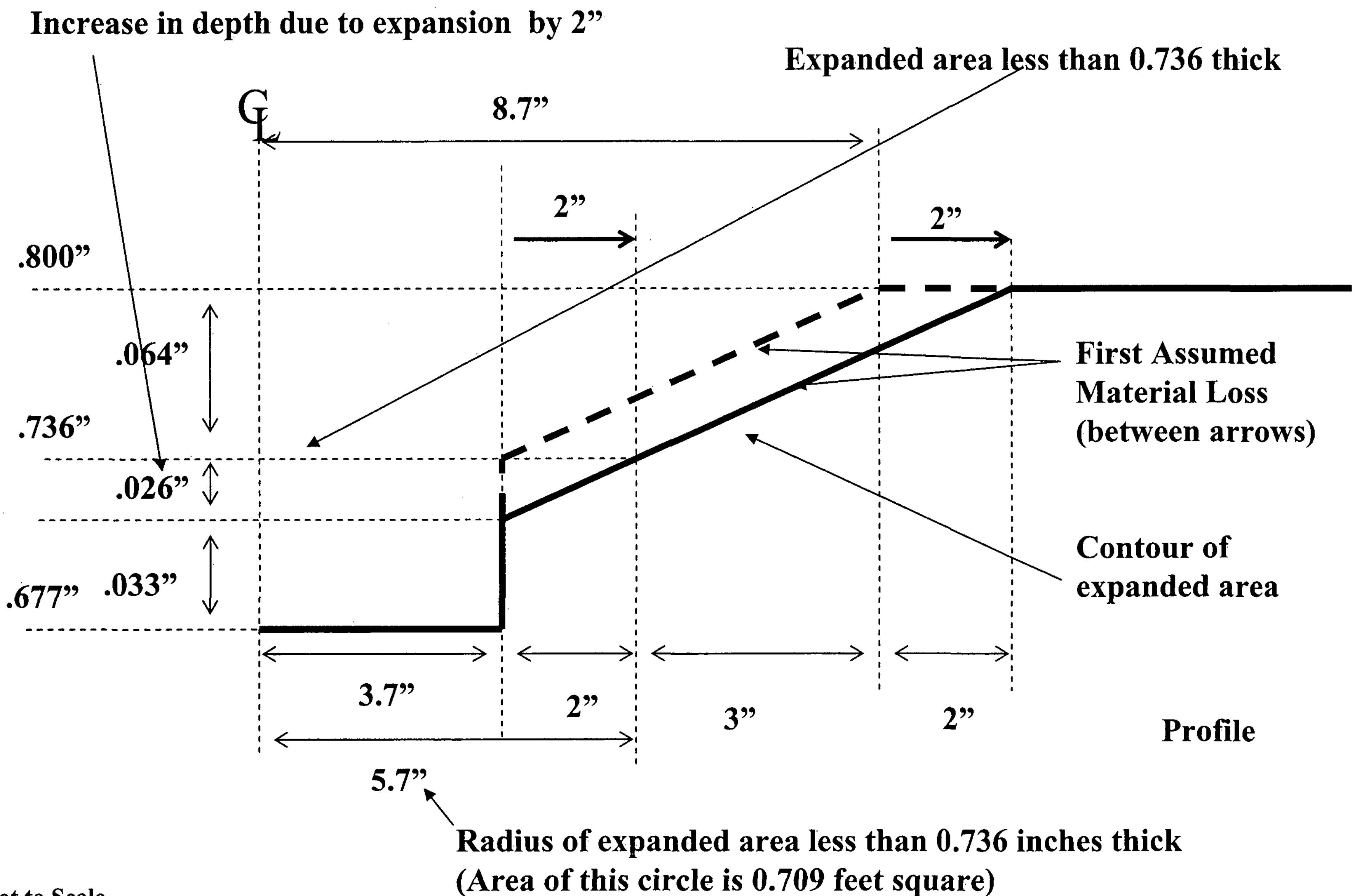
Profile

Figure 3



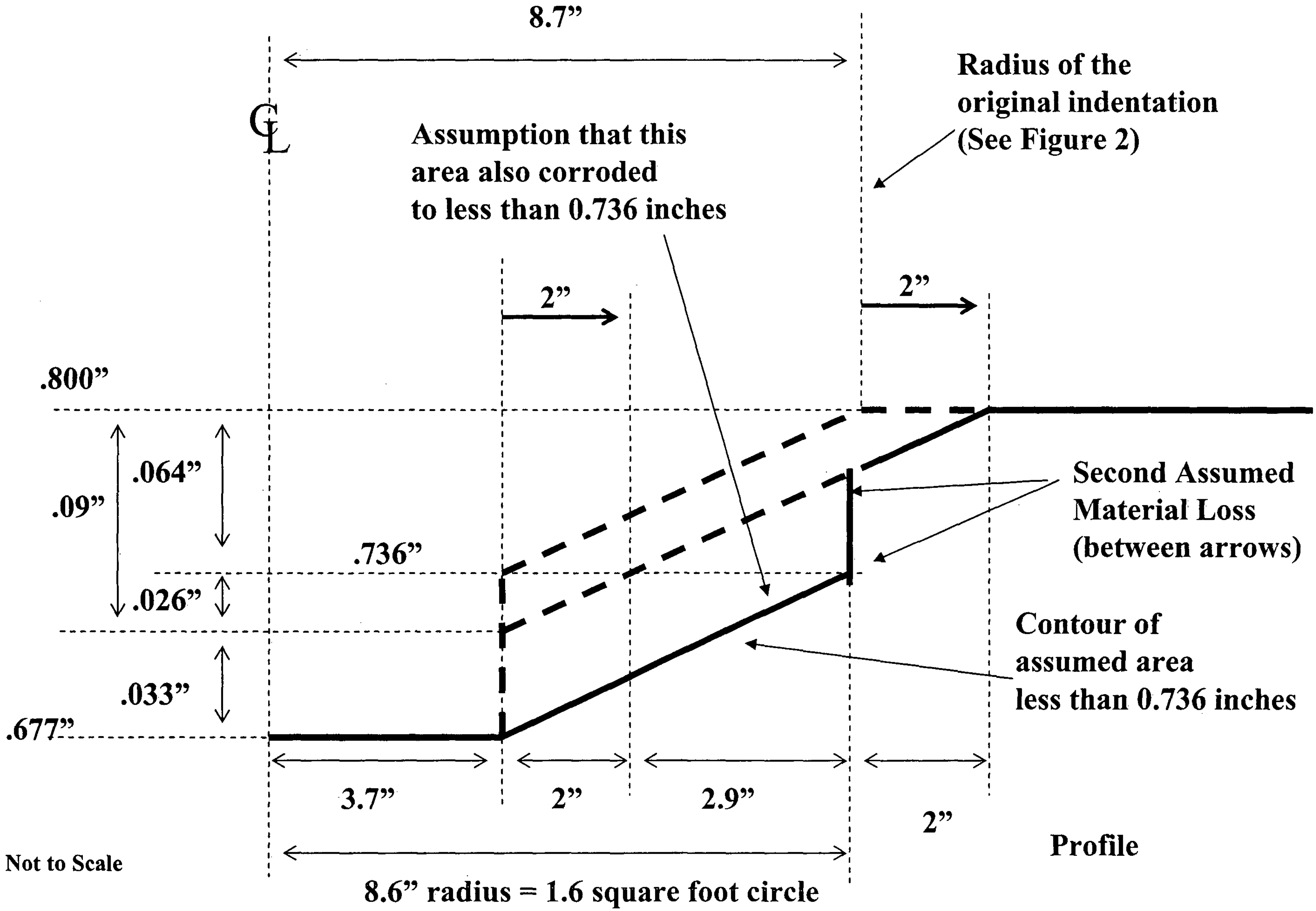
Not to Scale

Figure 4



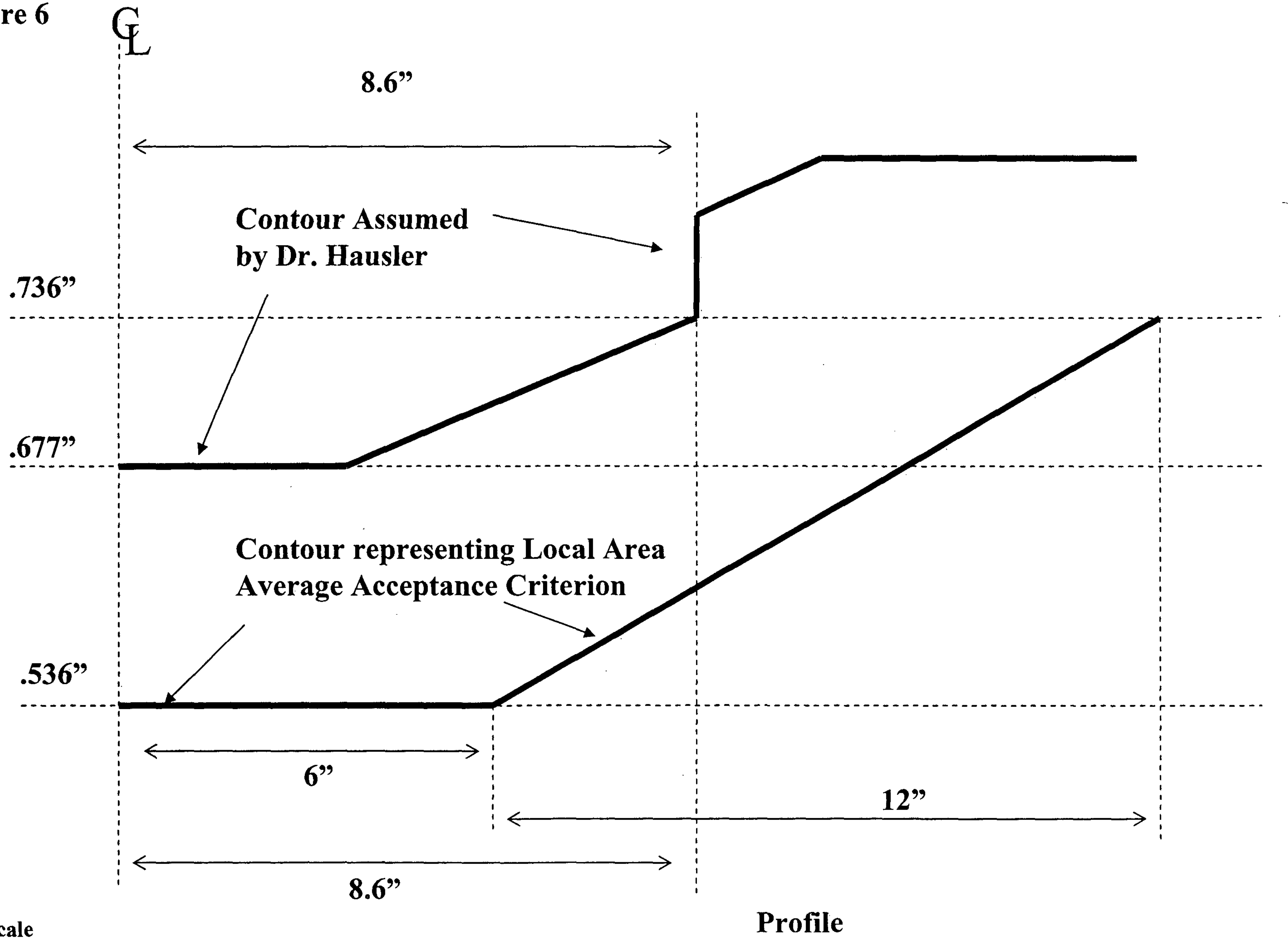
Not to Scale

Figure 5



Not to Scale

Figure 6



Not to Scale